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(54) **METHOD OF CREATING A CASING IN A BOREHOLE**

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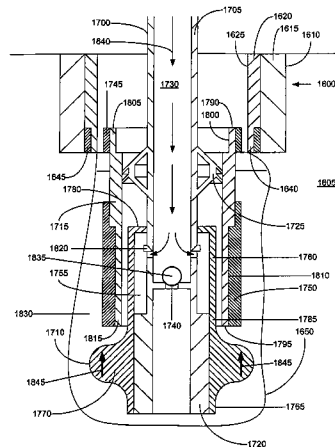
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(57) **ABSTRACT**

A method of creating a casing in a borehole located in a subterranean formation including: supporting a tubular liner and an expansion device in the borehole using a support member; injecting fluidic material into the borehole; pressurizing an interior region of the expansion device; displacing a portion of the expansion device relative to the support member and the tubular liner in the longitudinal direction; and radially expanding the tubular liner.

26 Claims, 47 Drawing Sheets



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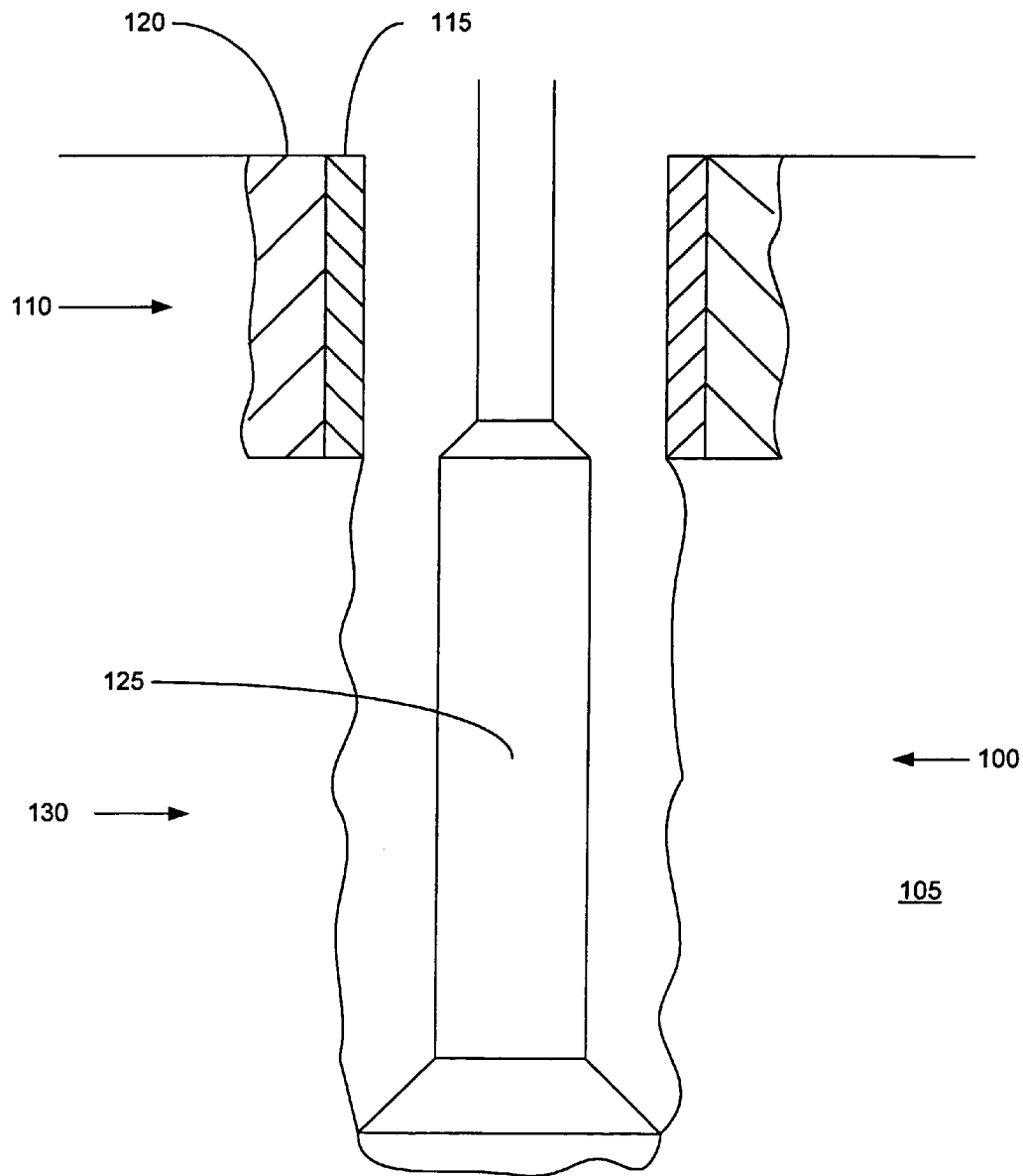
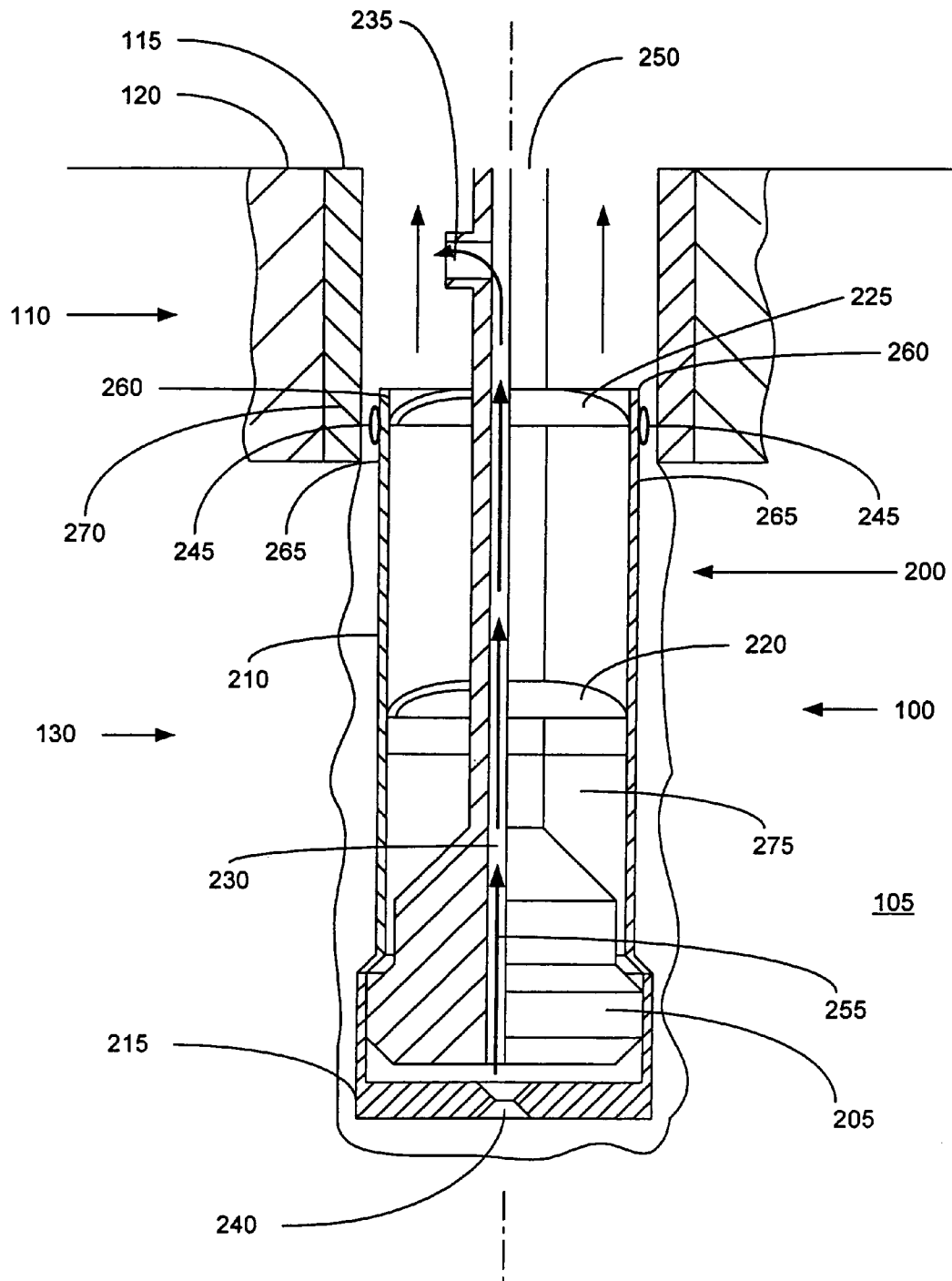
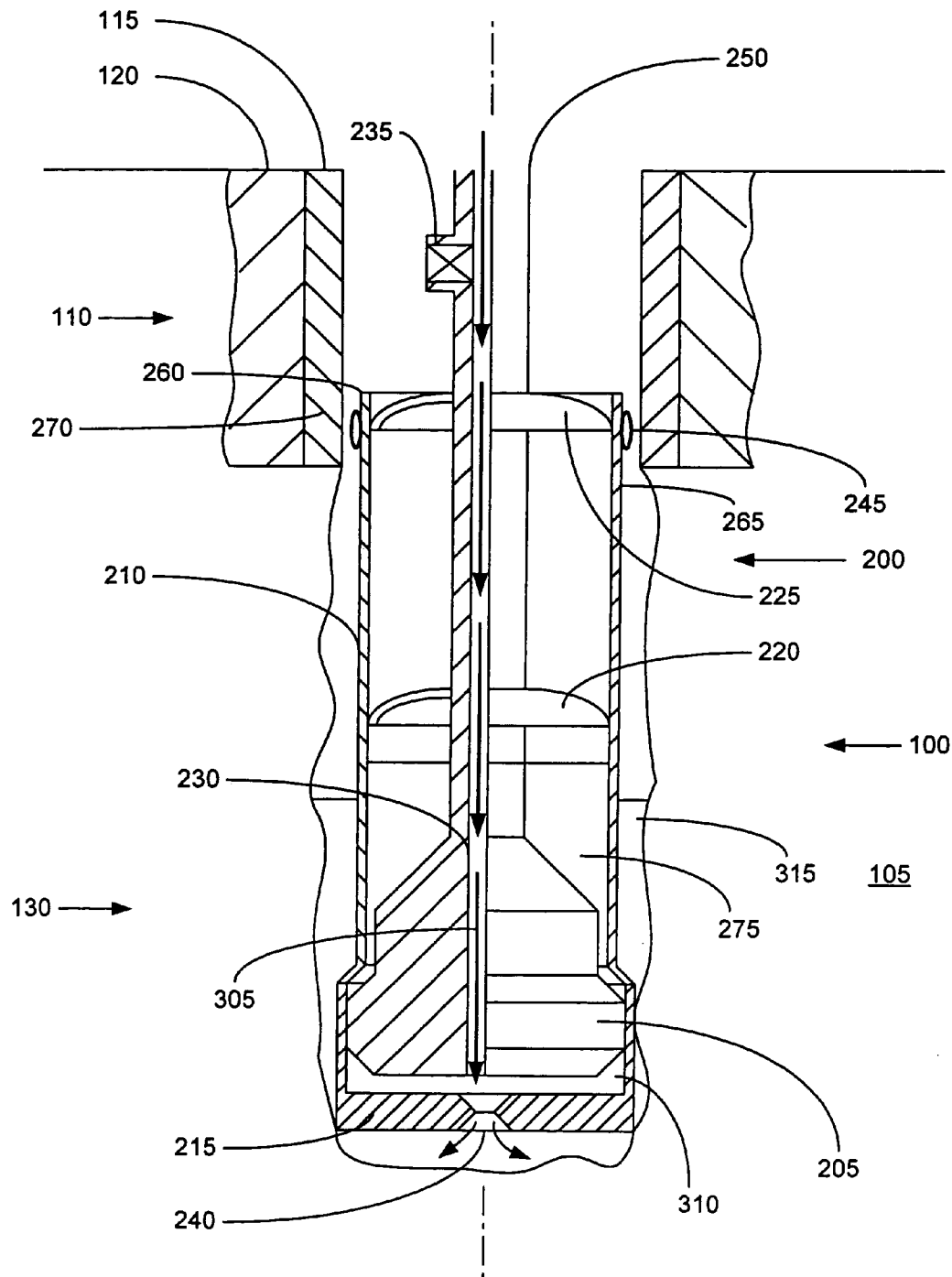


FIGURE 1





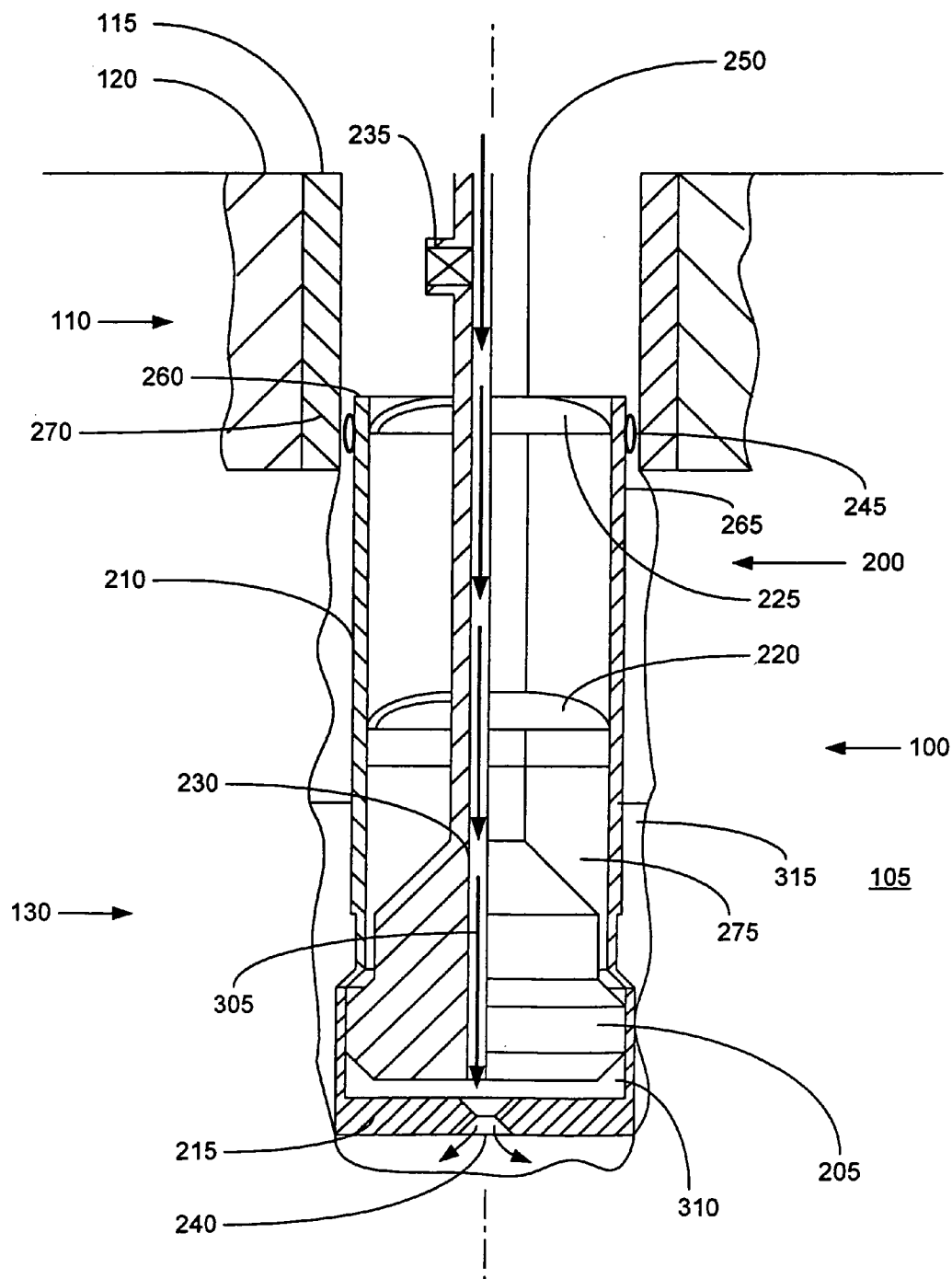


FIGURE 3a

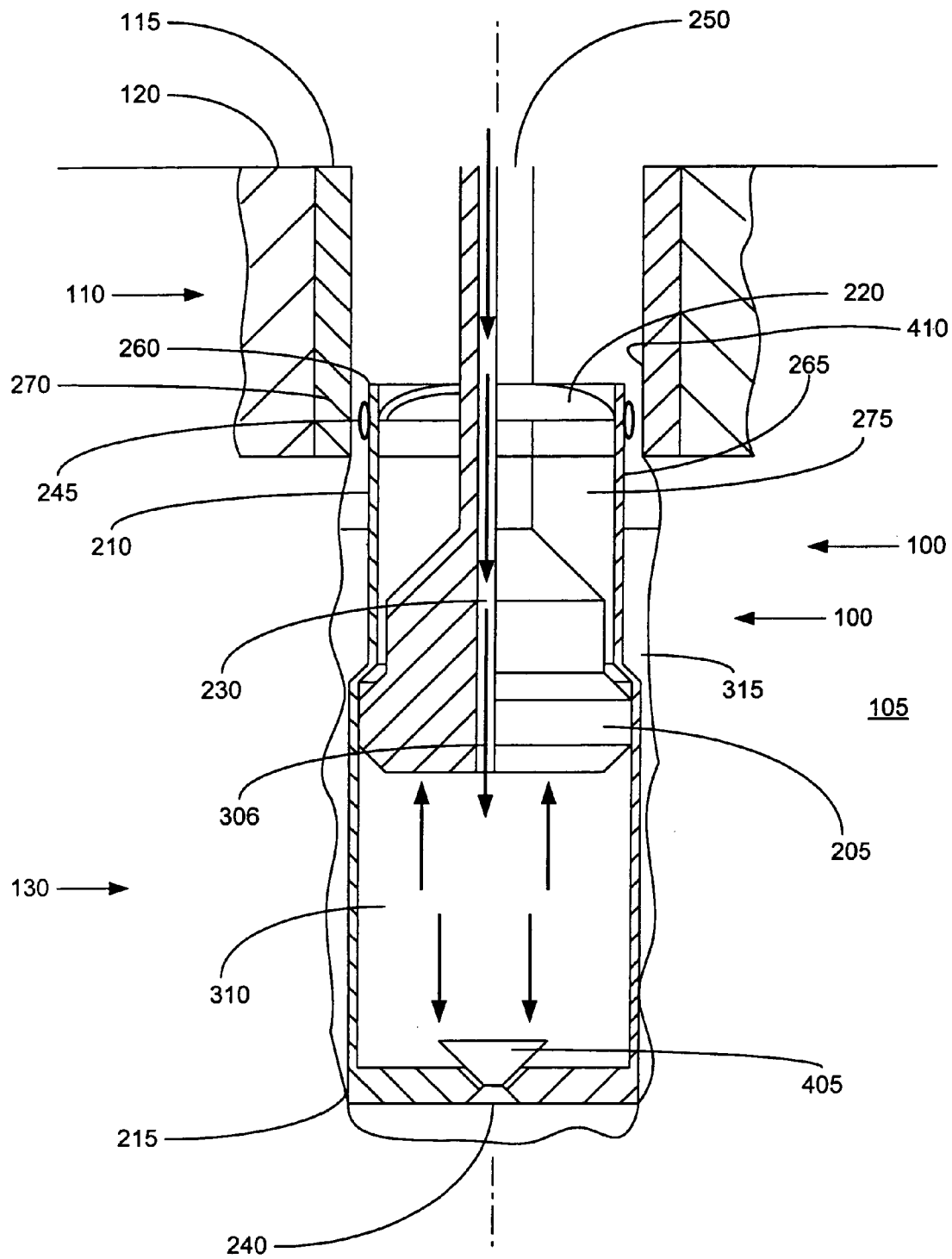


FIGURE 4

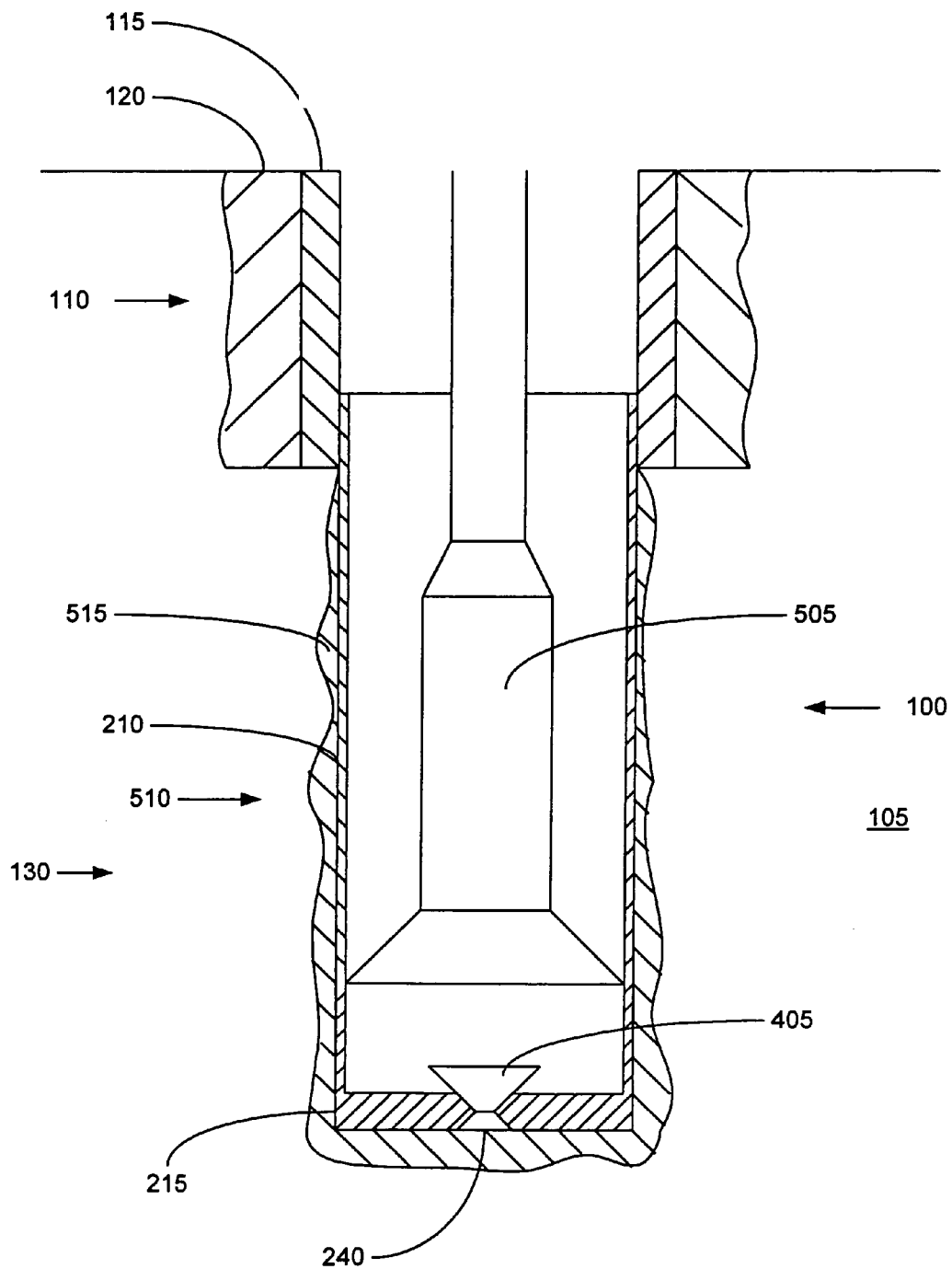


FIGURE 5

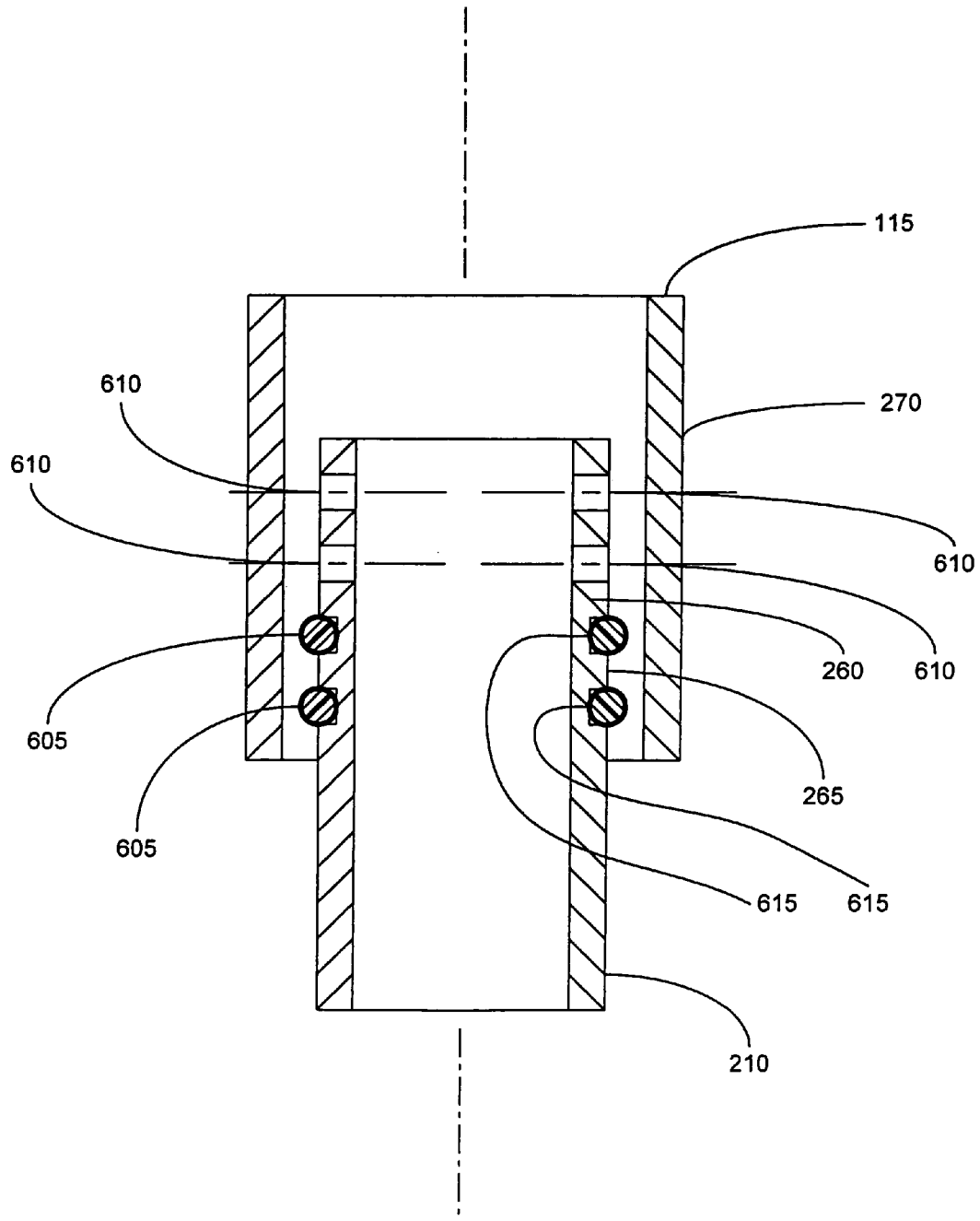


FIGURE 6

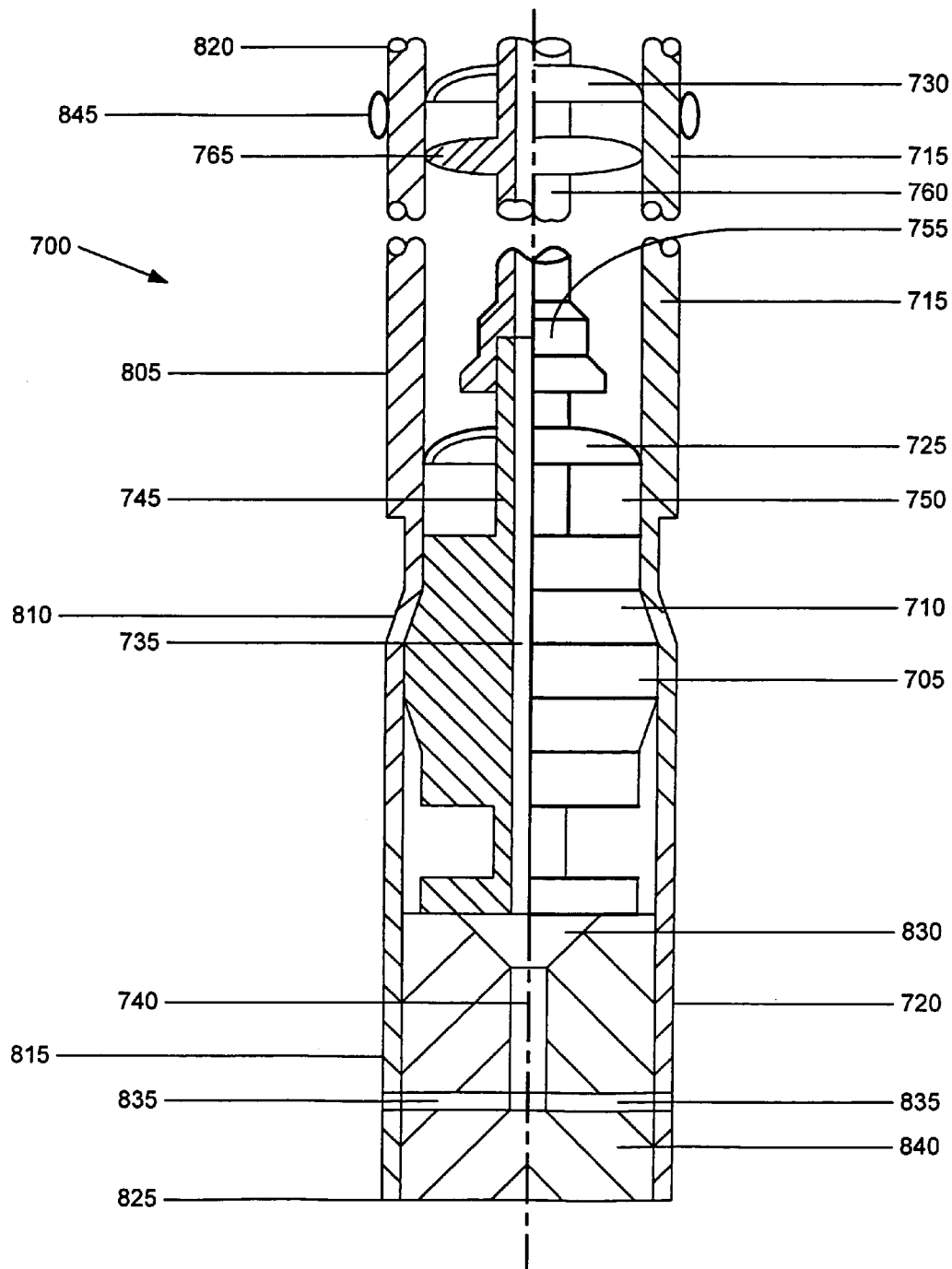


FIGURE 7

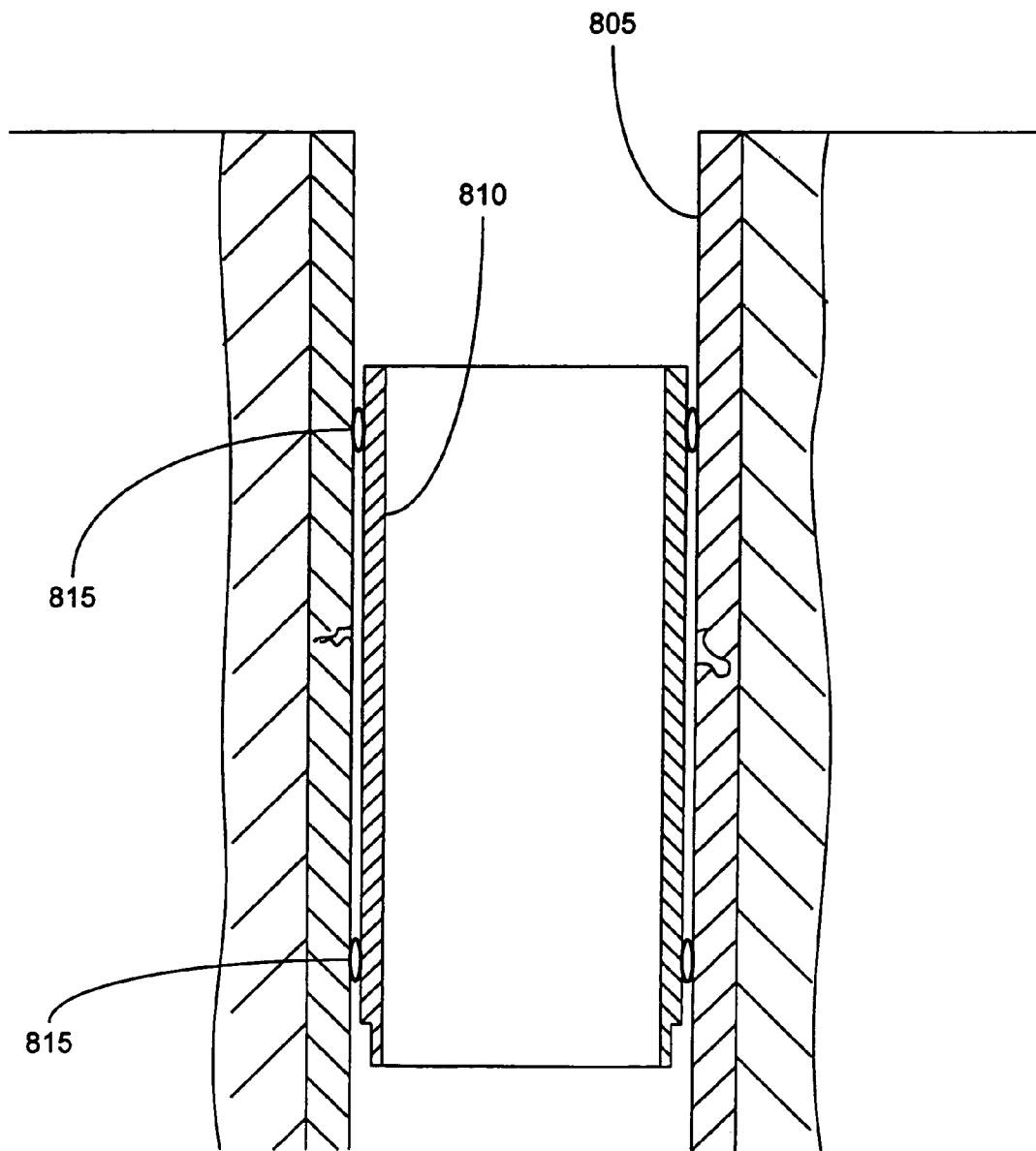


FIGURE 8

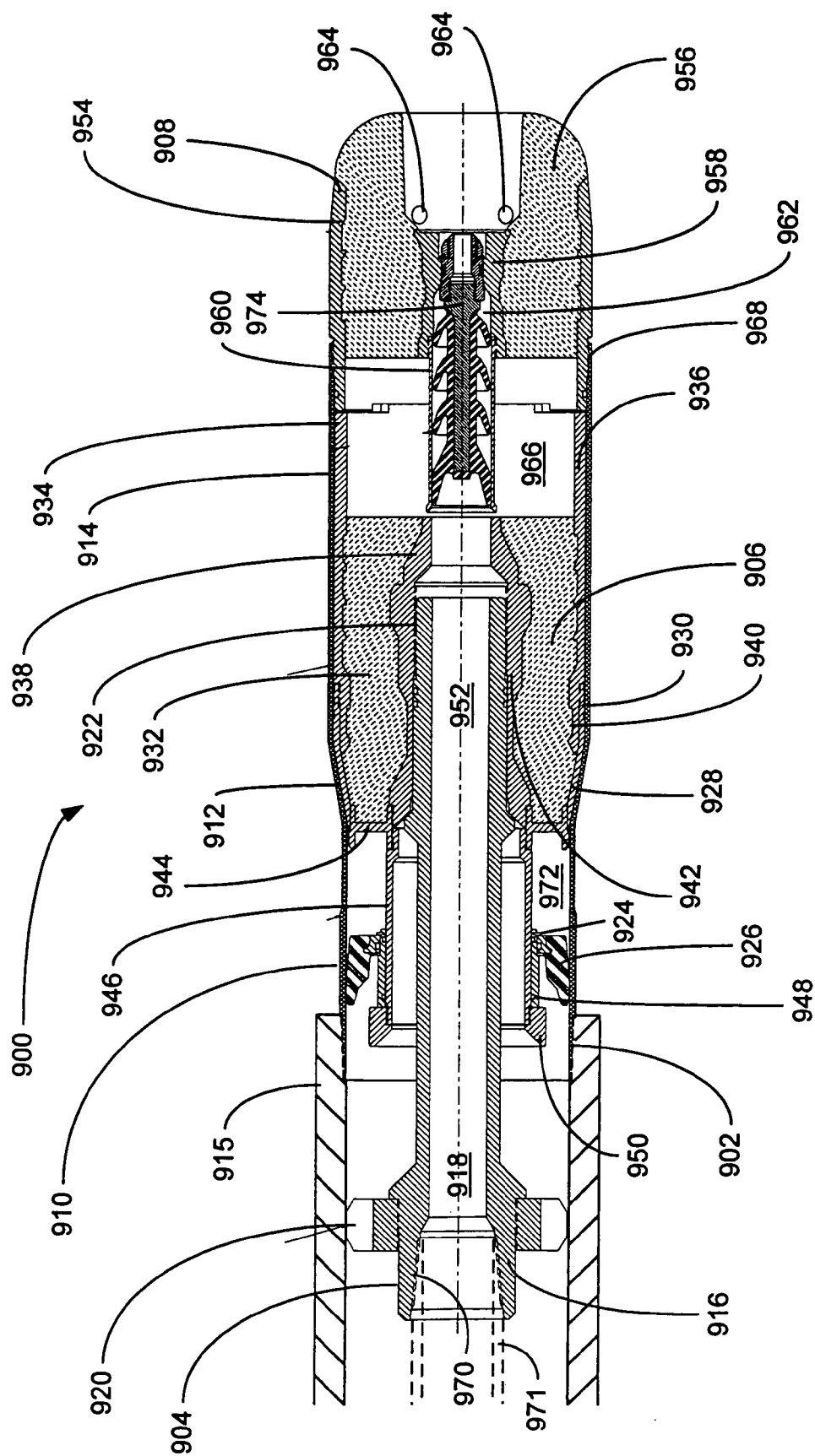


FIGURE 9

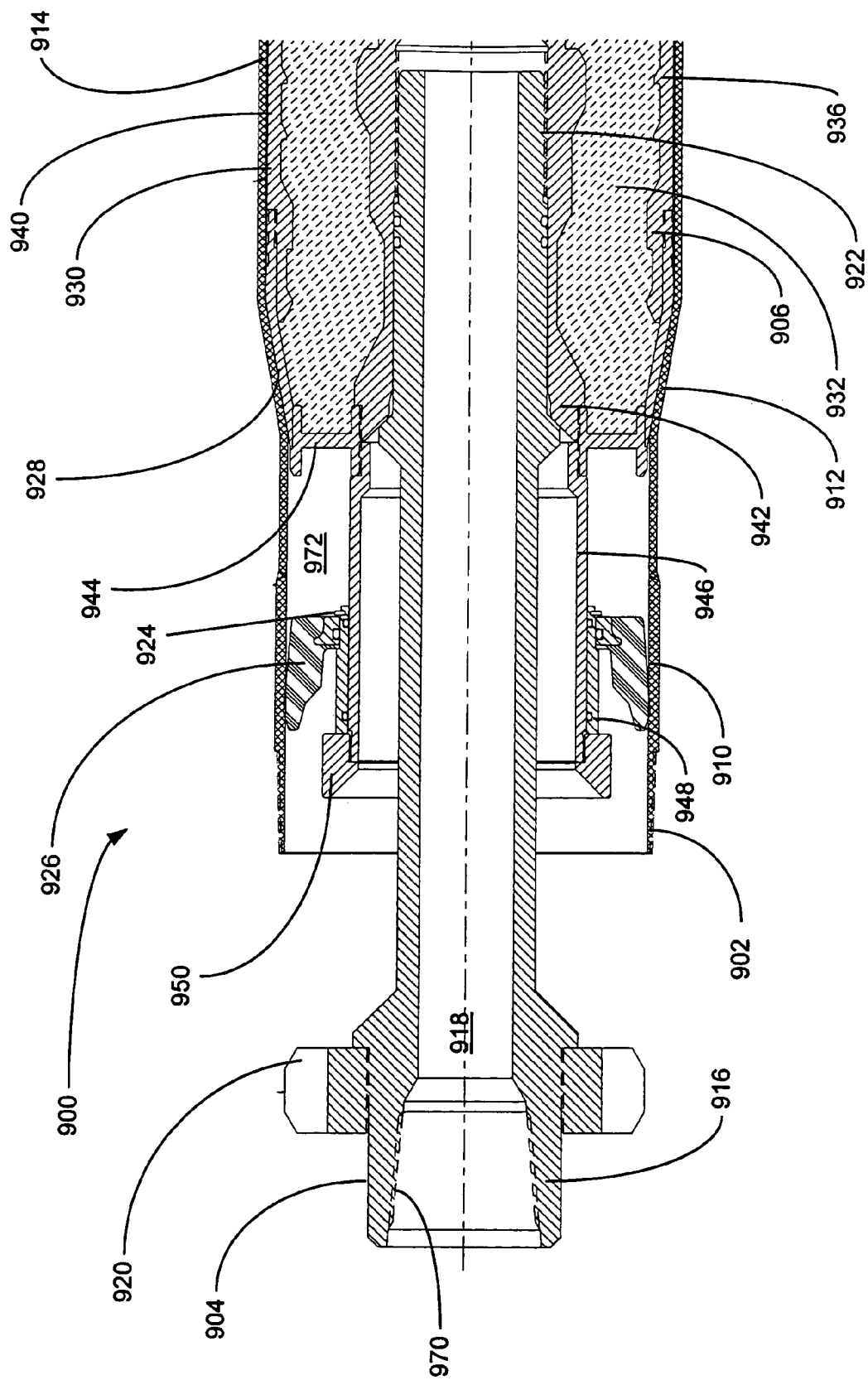


FIGURE 9a

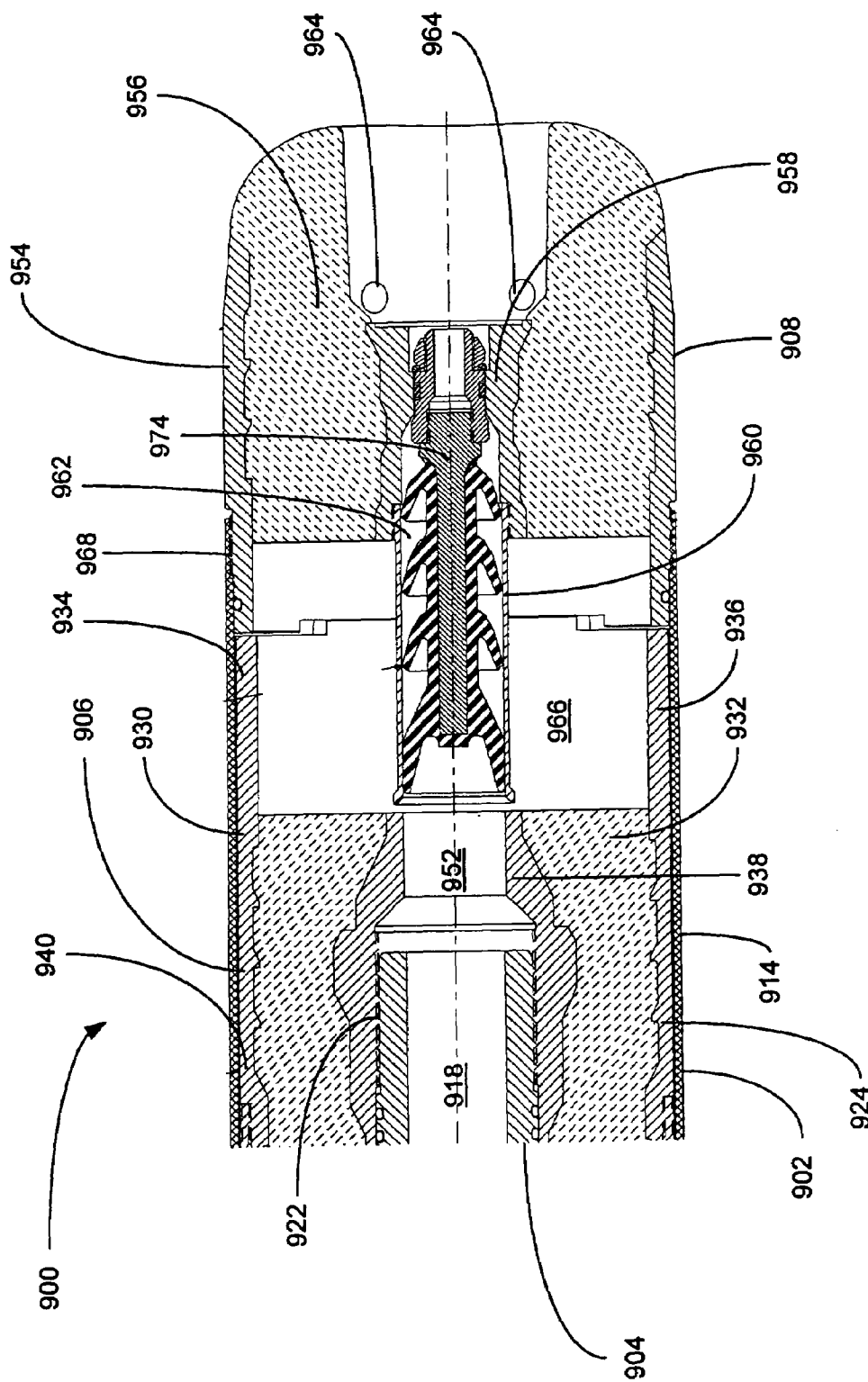


FIGURE 9b

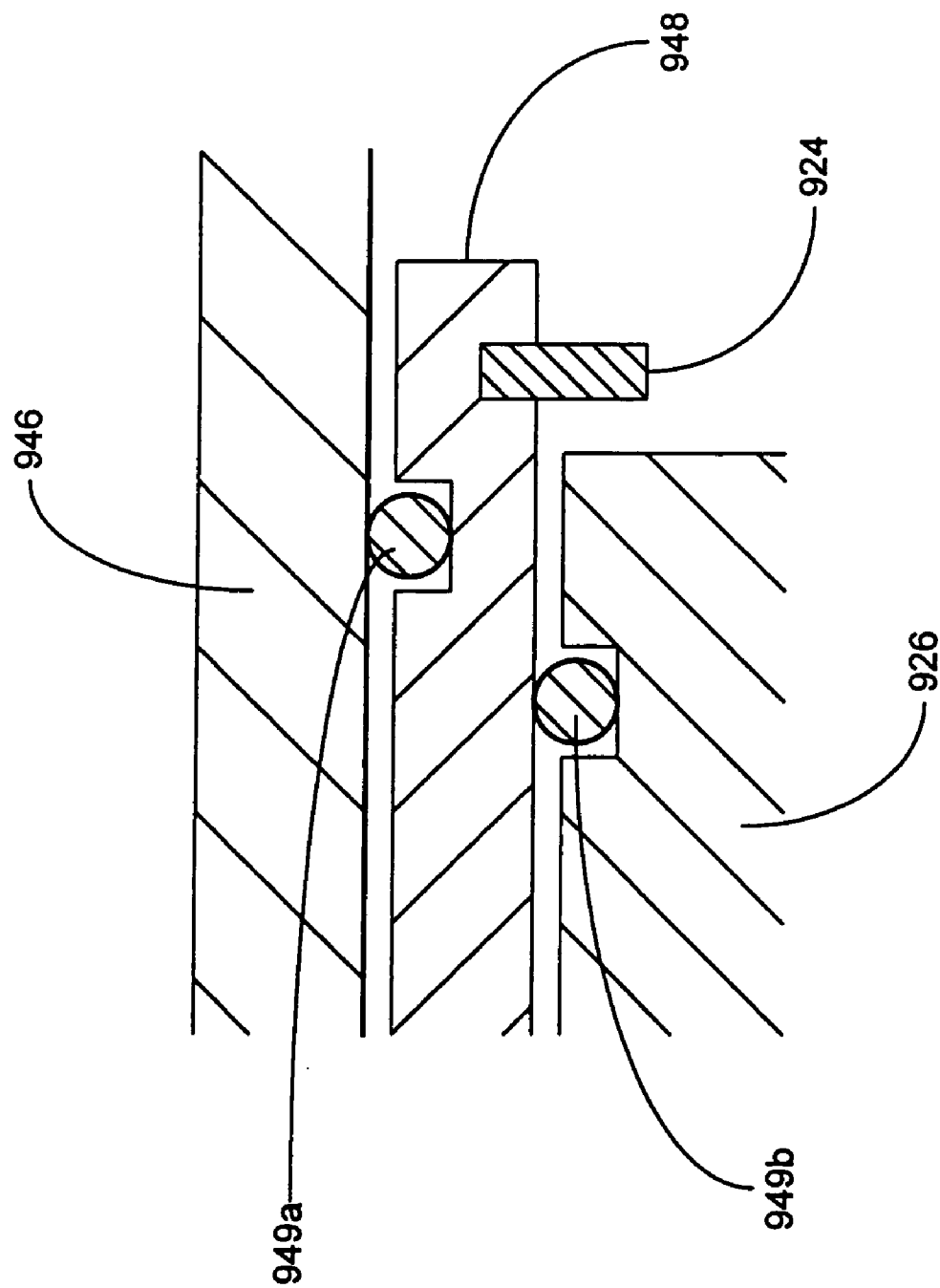


FIGURE 9C

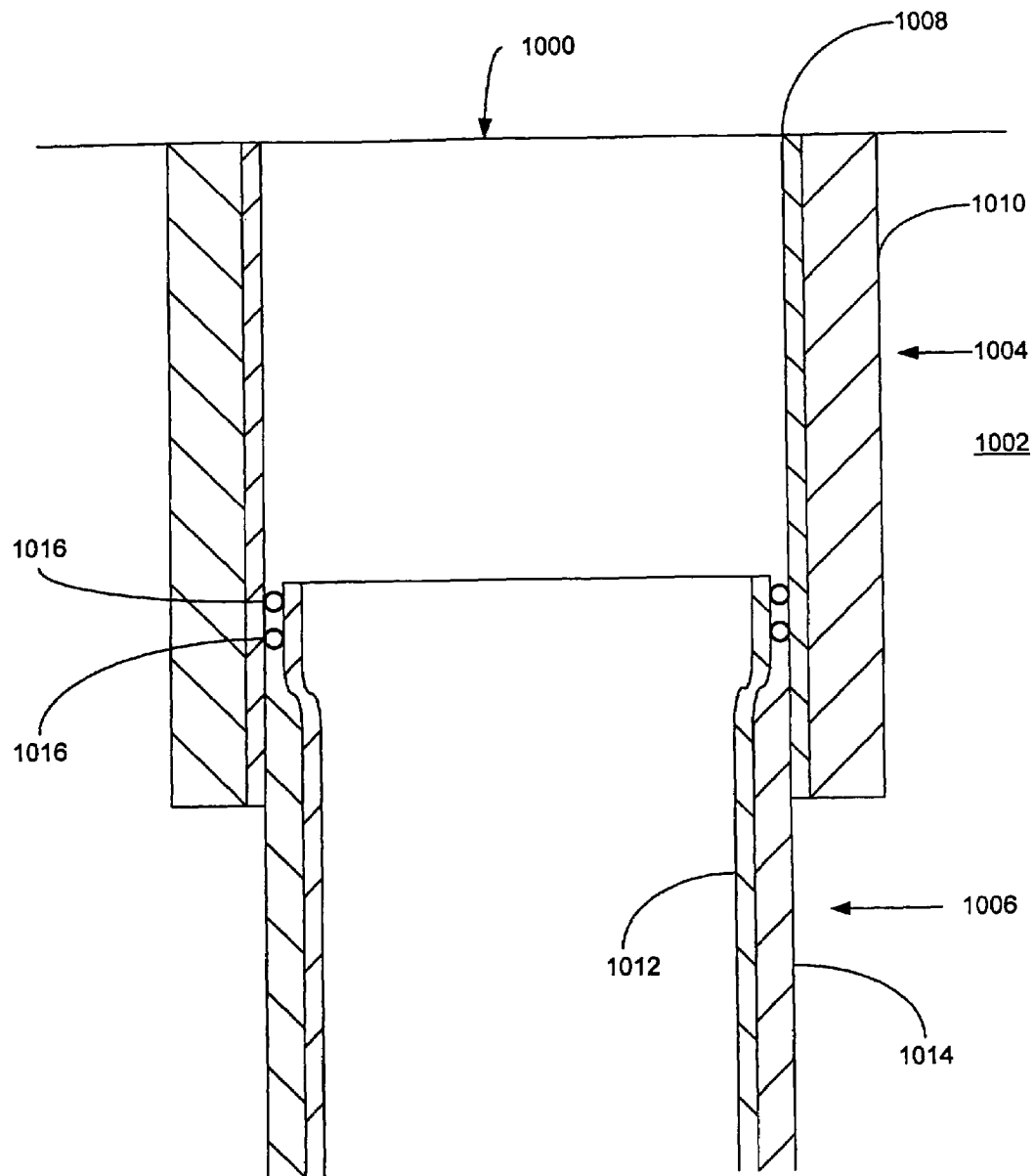


FIGURE 10a

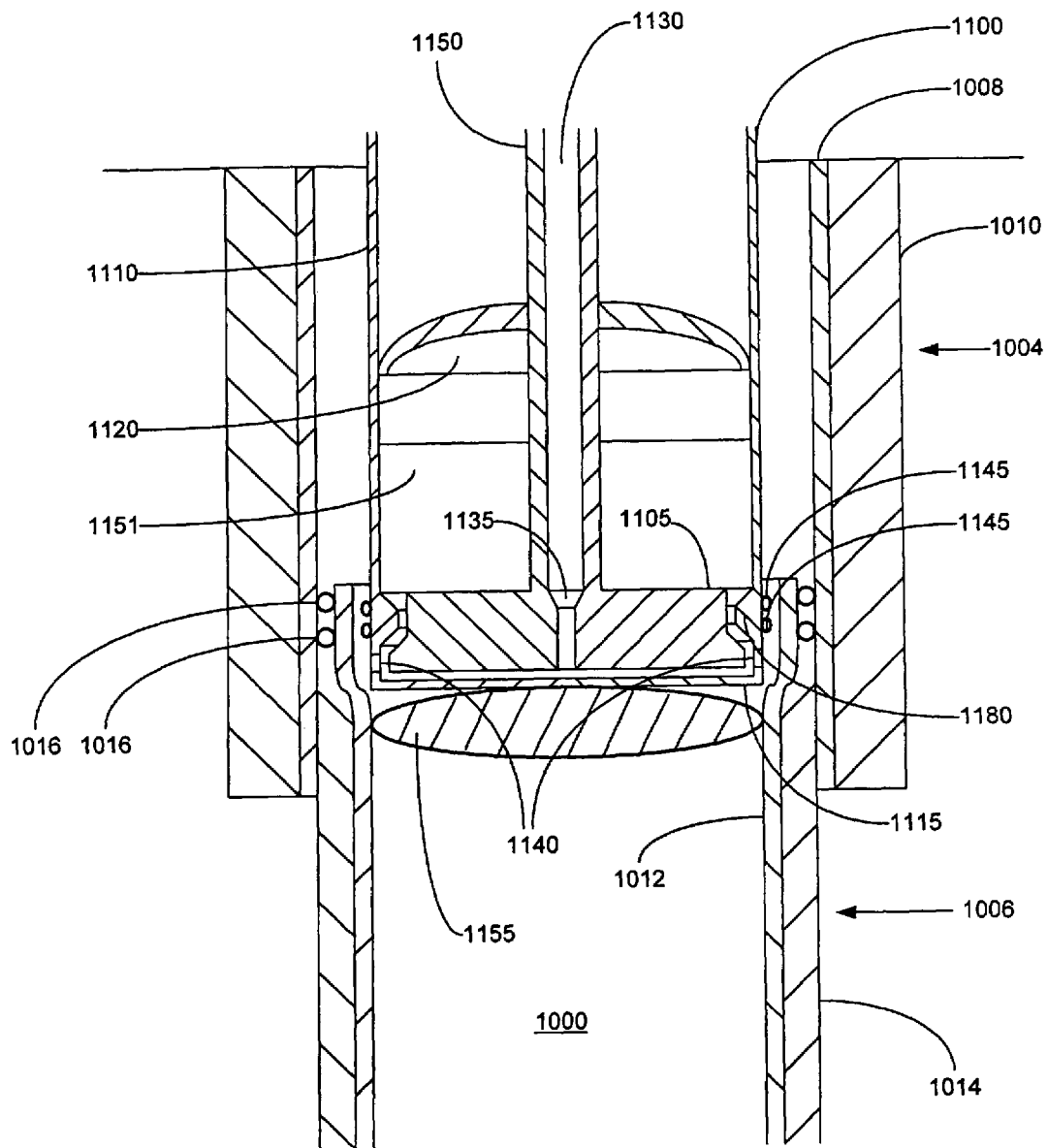


FIGURE 10b

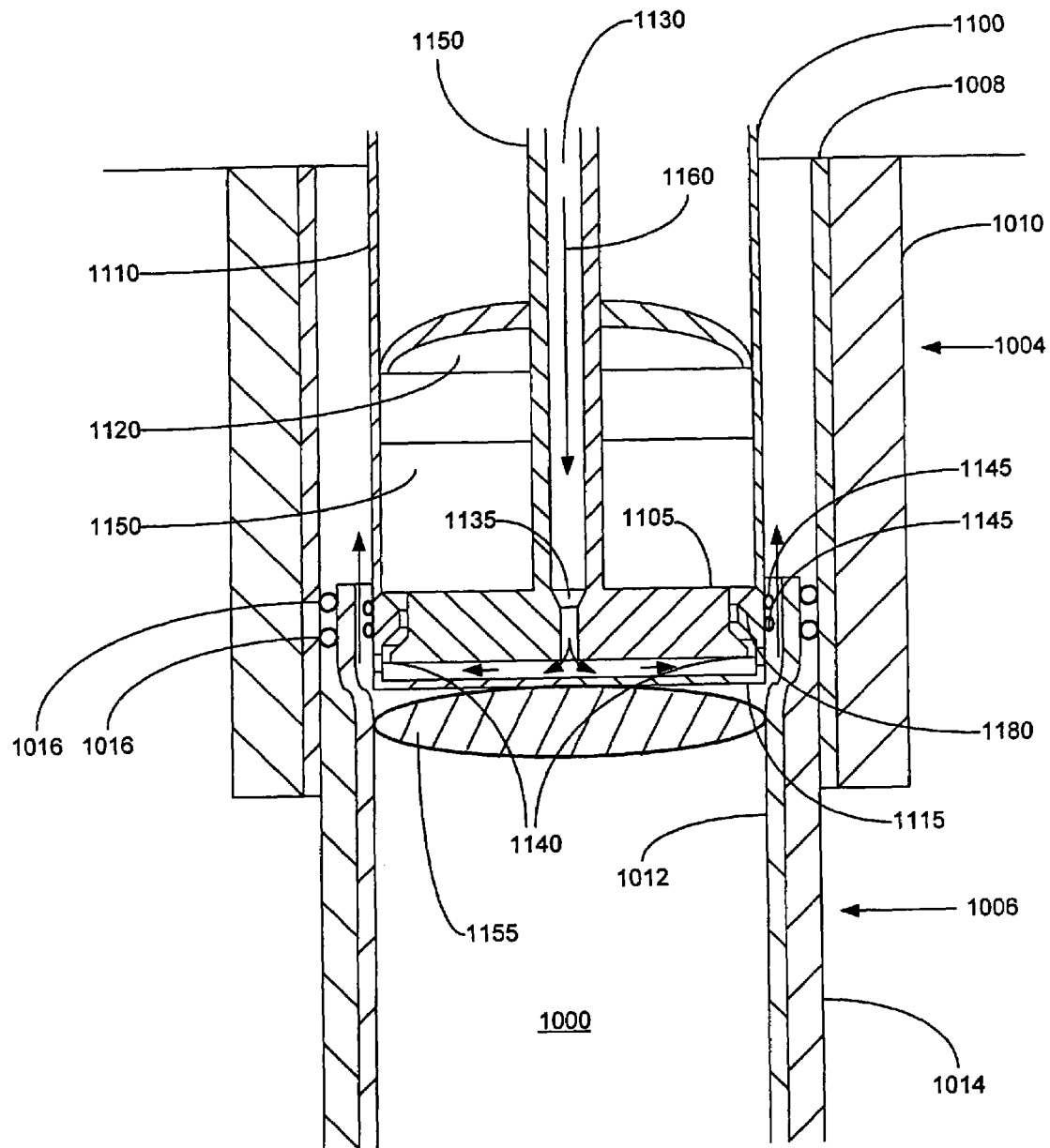


FIGURE 10c

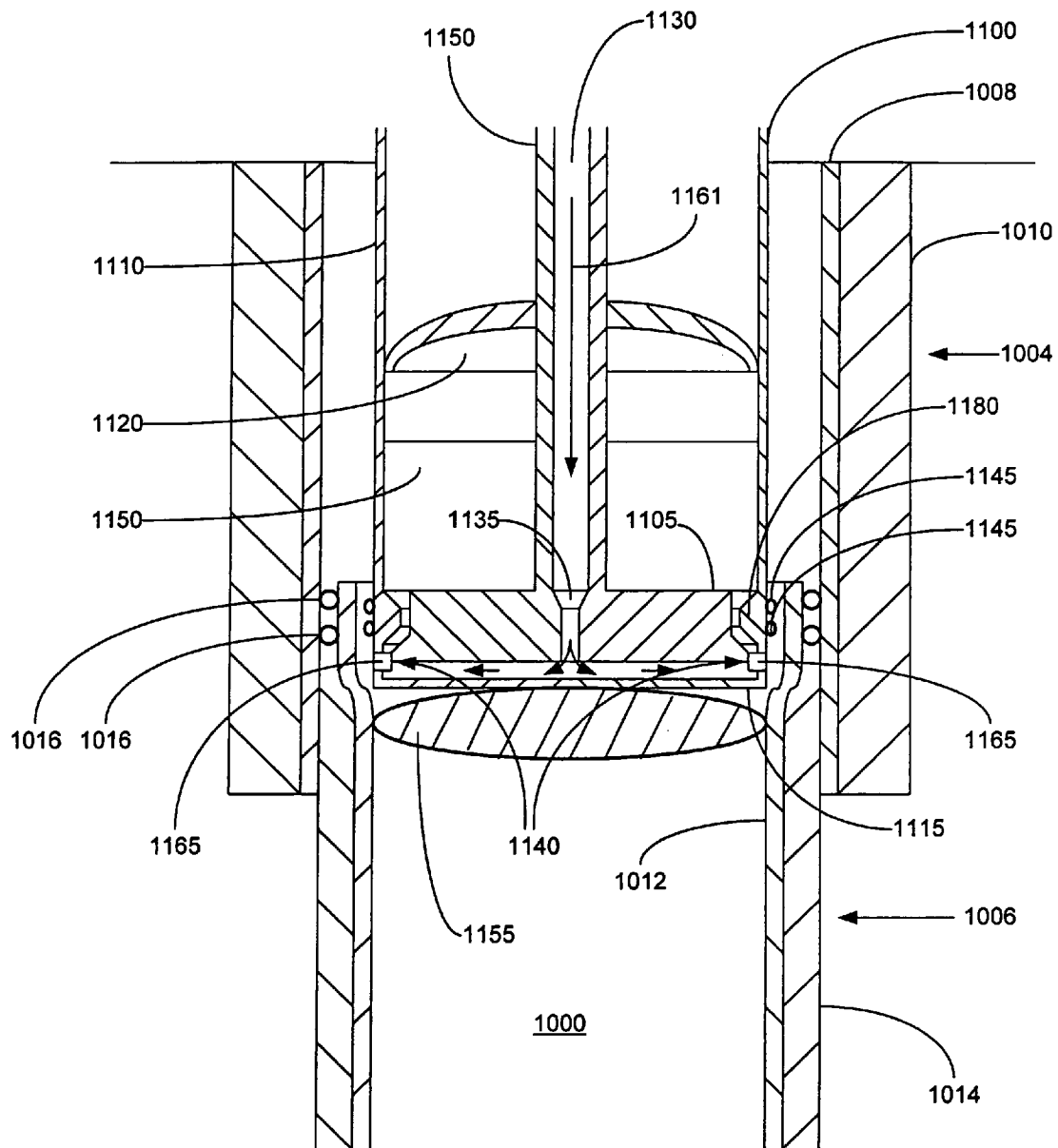


FIGURE 10d

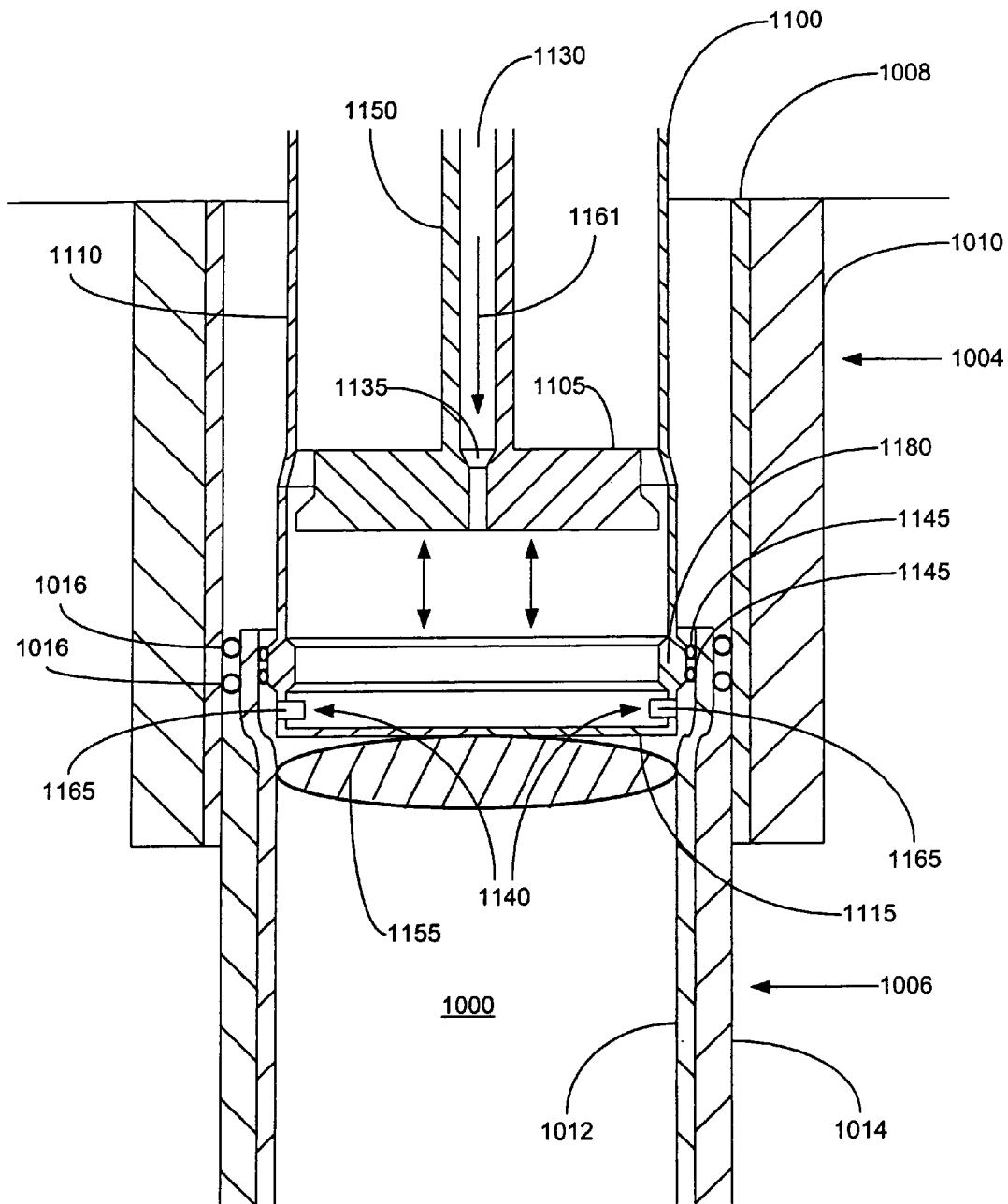


FIGURE 10e

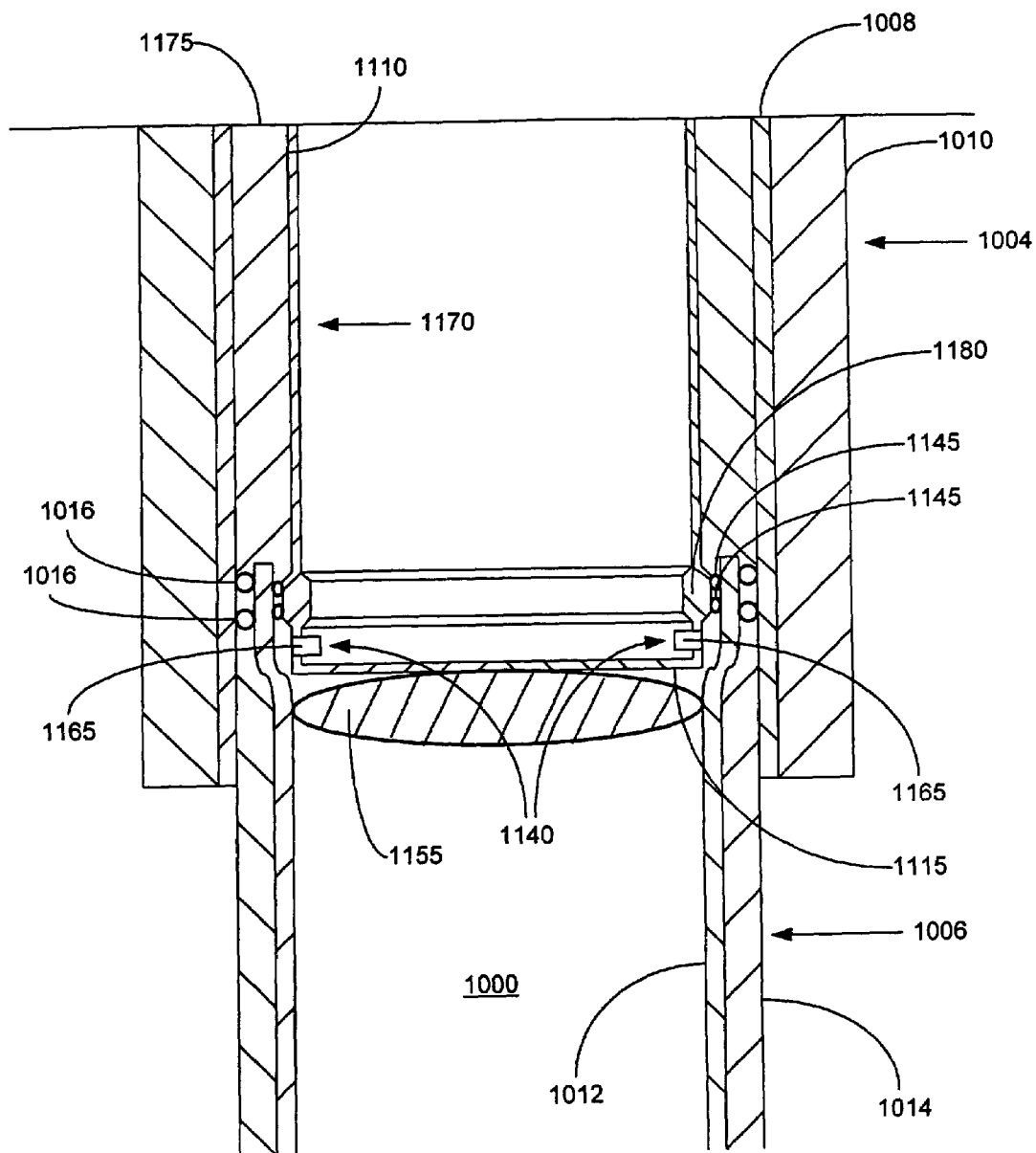


FIGURE 10f

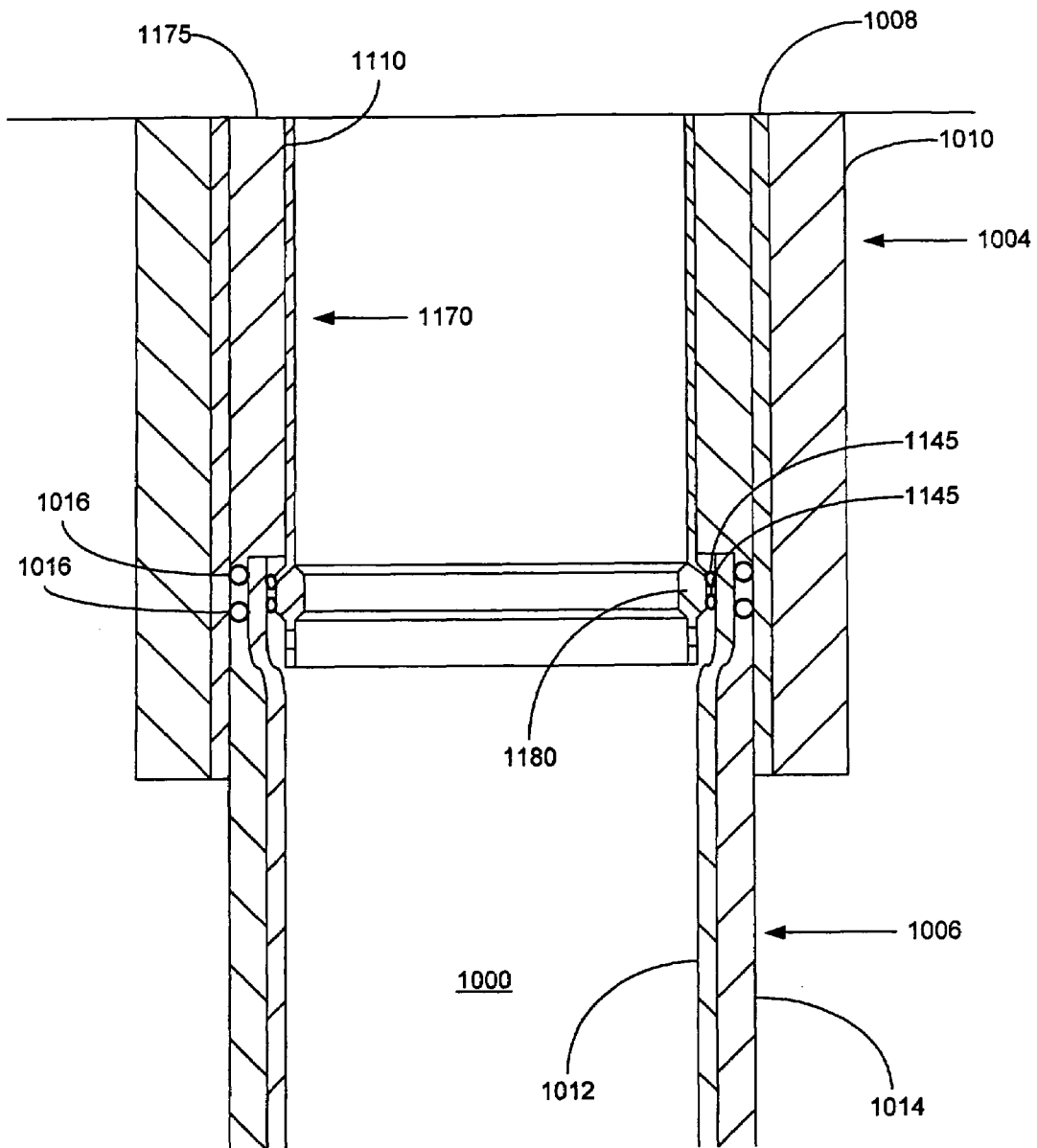


FIGURE 10g

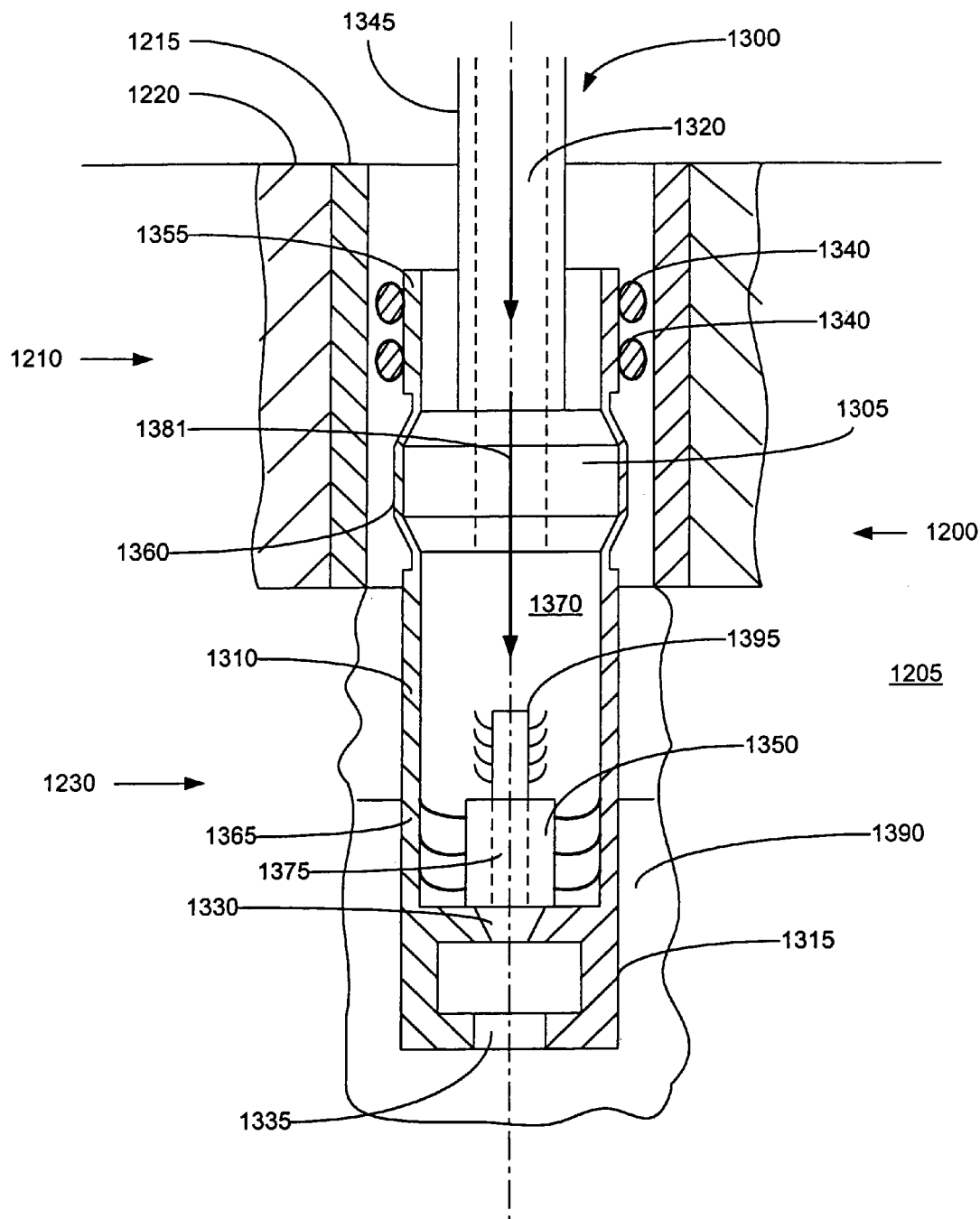


FIGURE 11

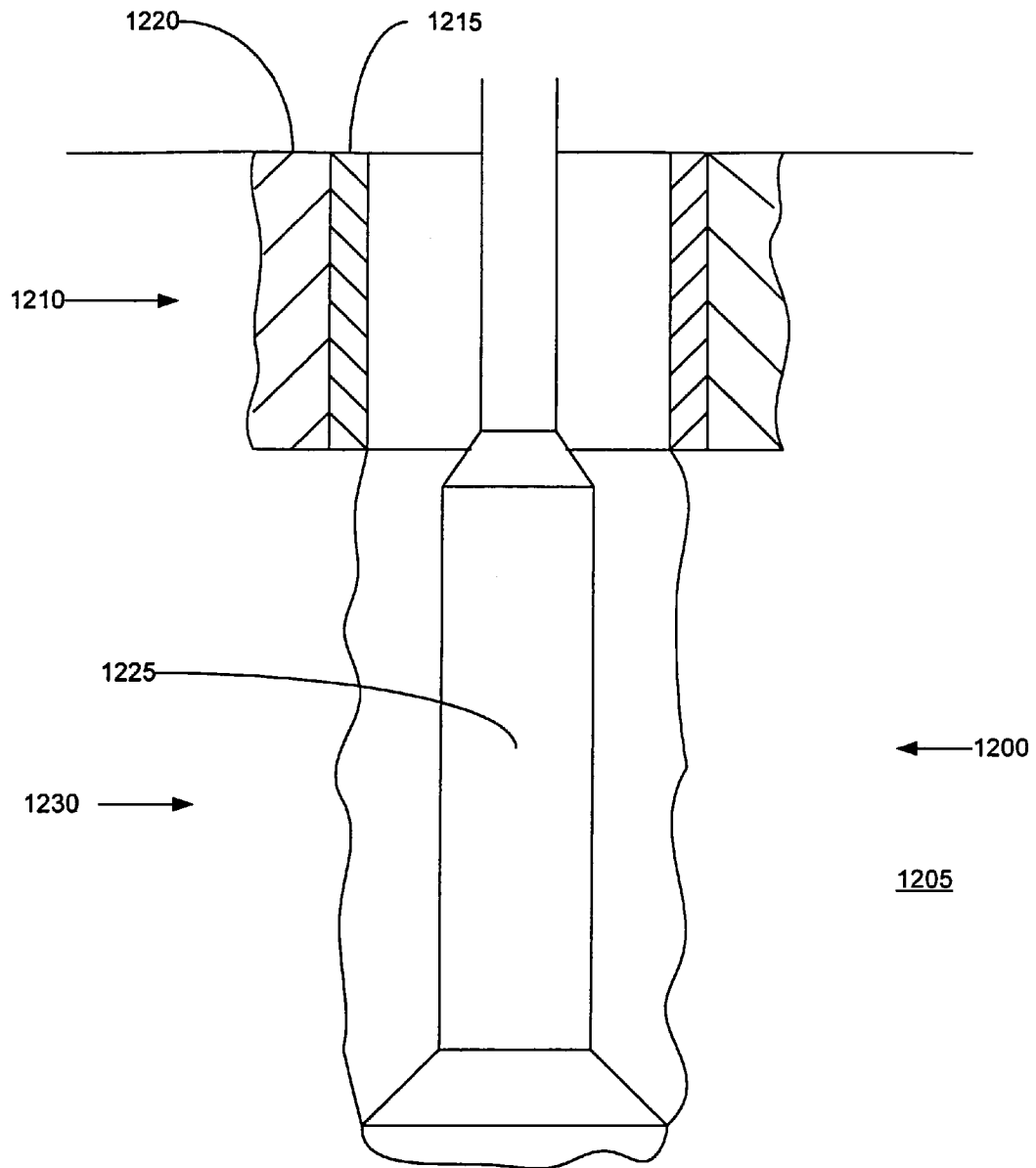


FIGURE 11a

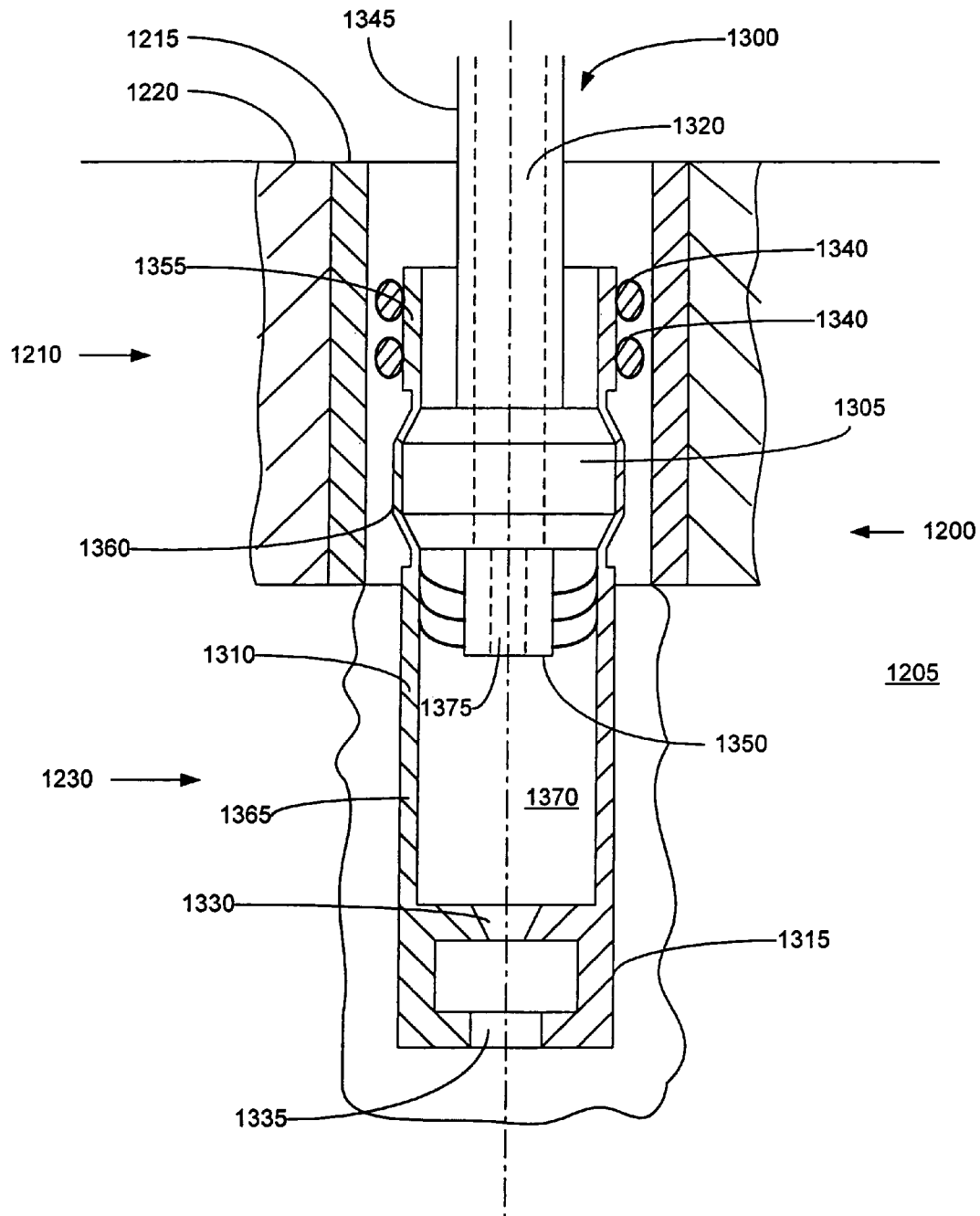


FIGURE 11b

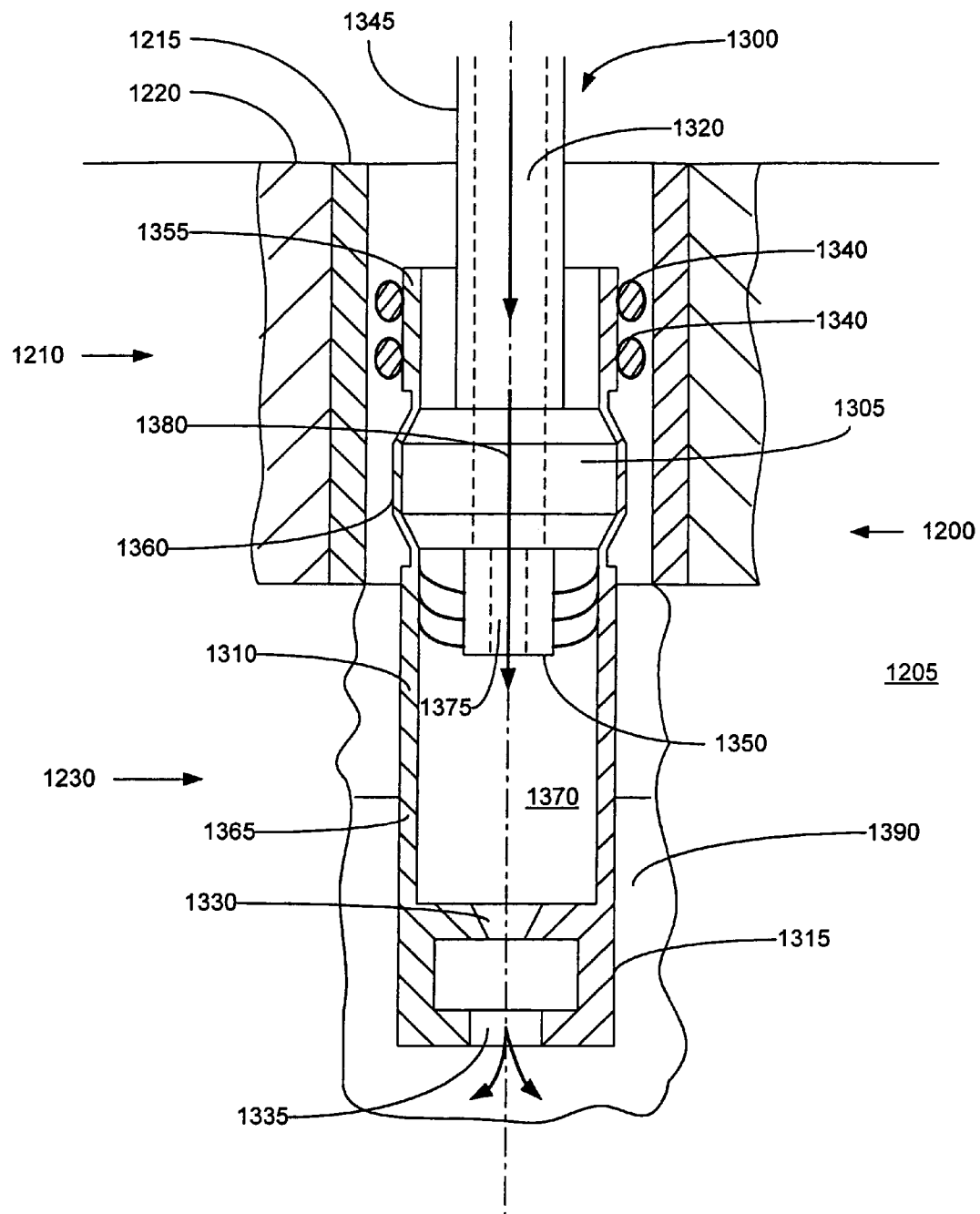


FIGURE 11c

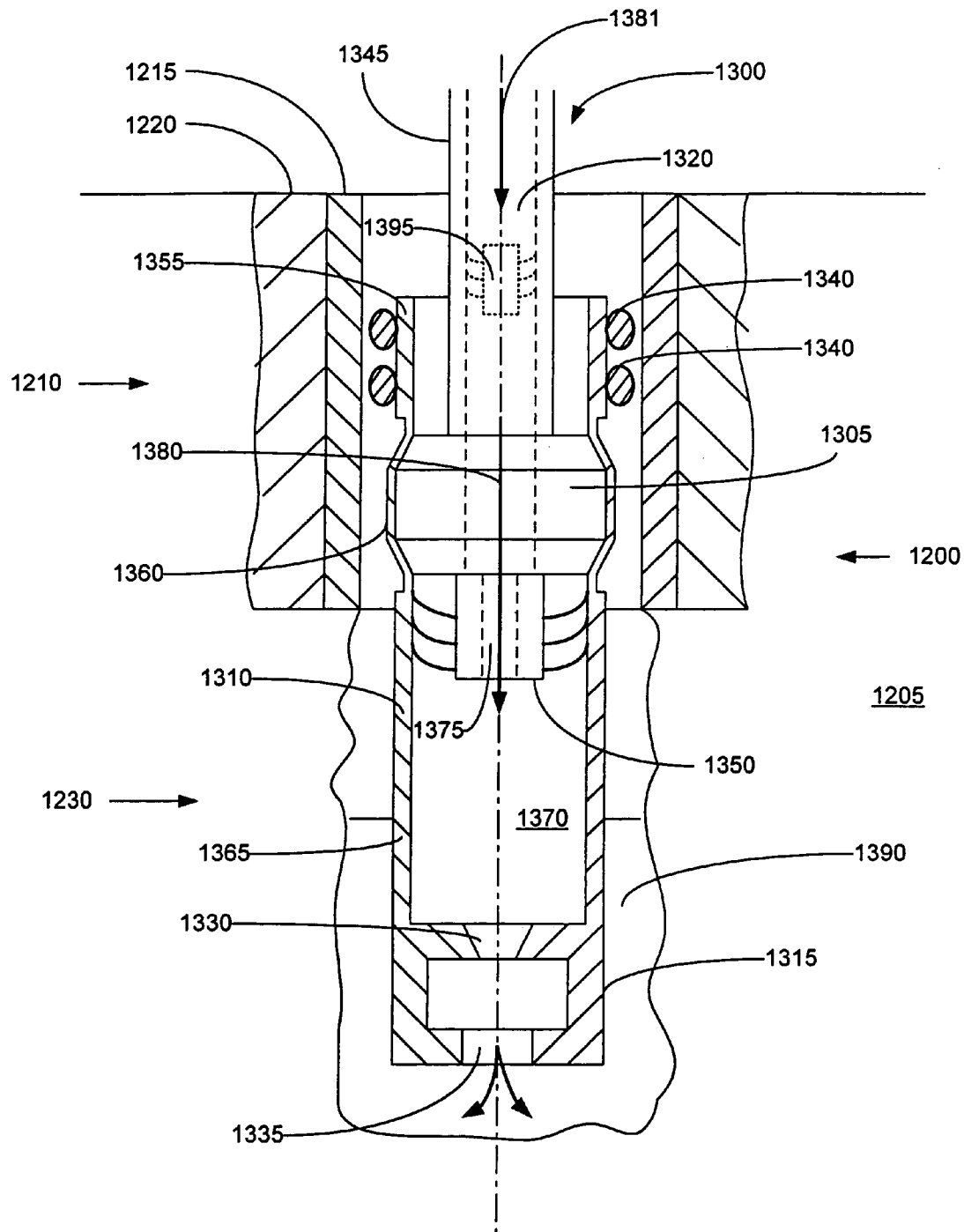


FIGURE 11d

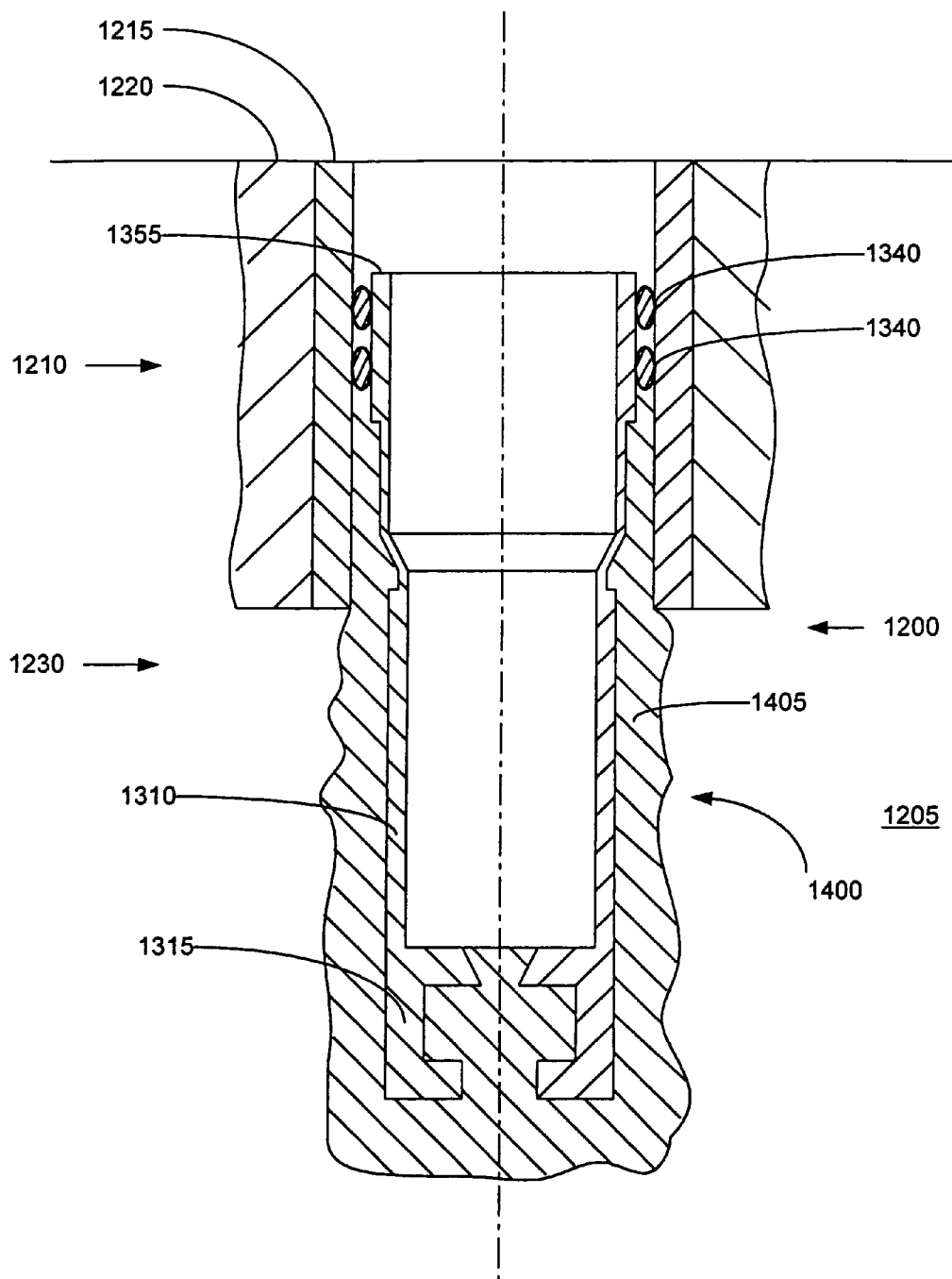


FIGURE 11f

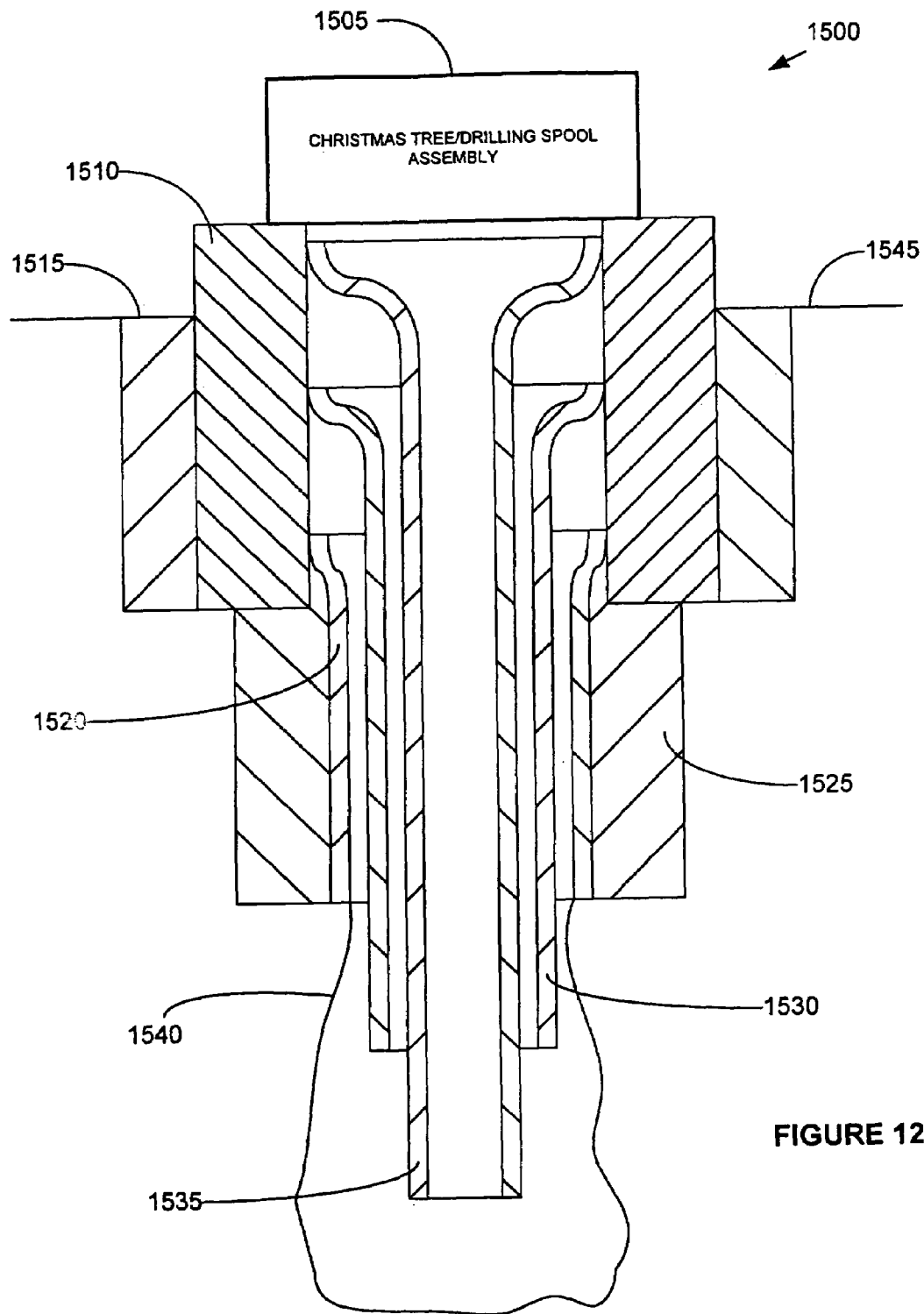


FIGURE 12

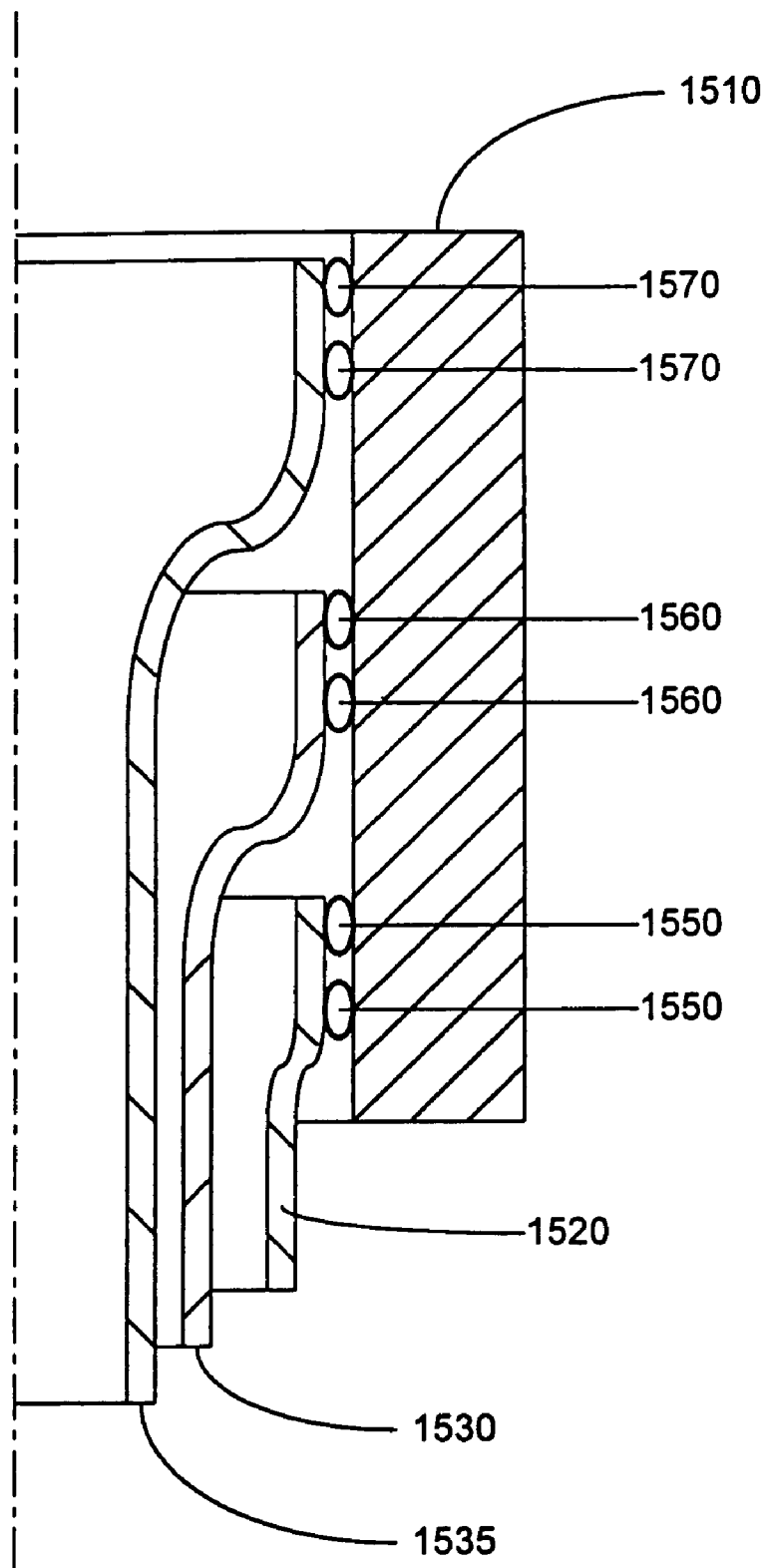


FIGURE 13

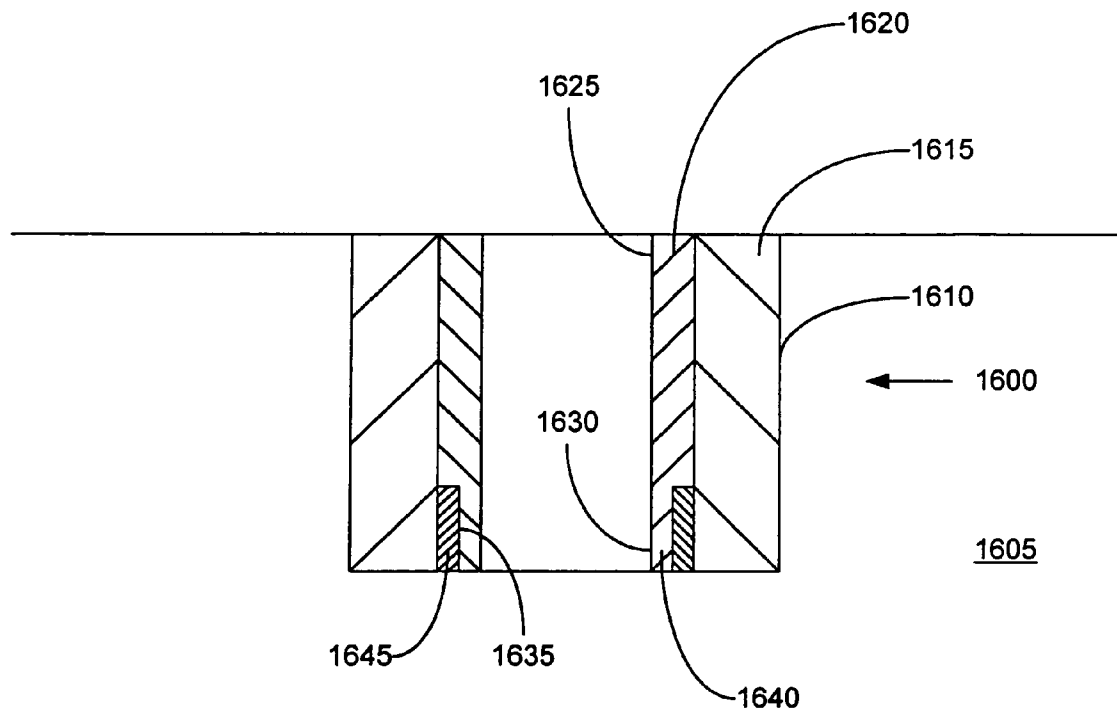


FIGURE 14a

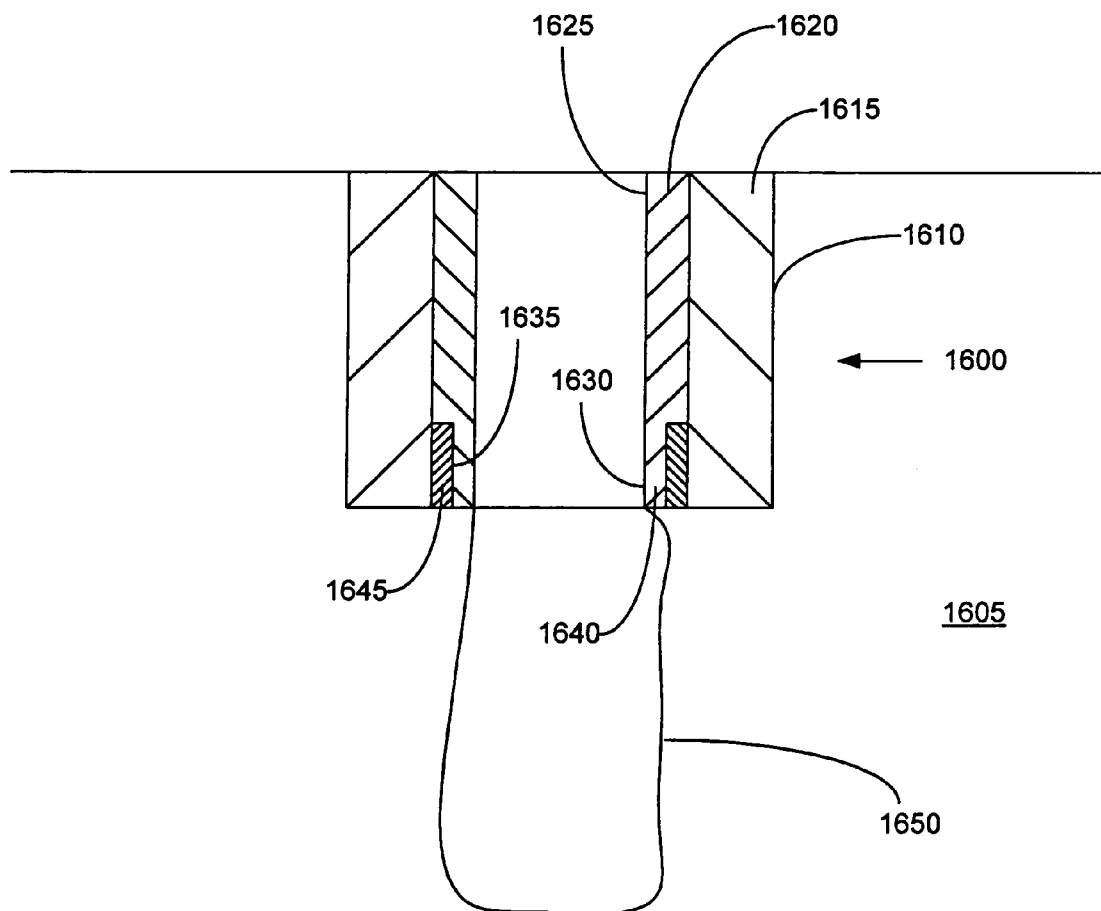


FIGURE 14b

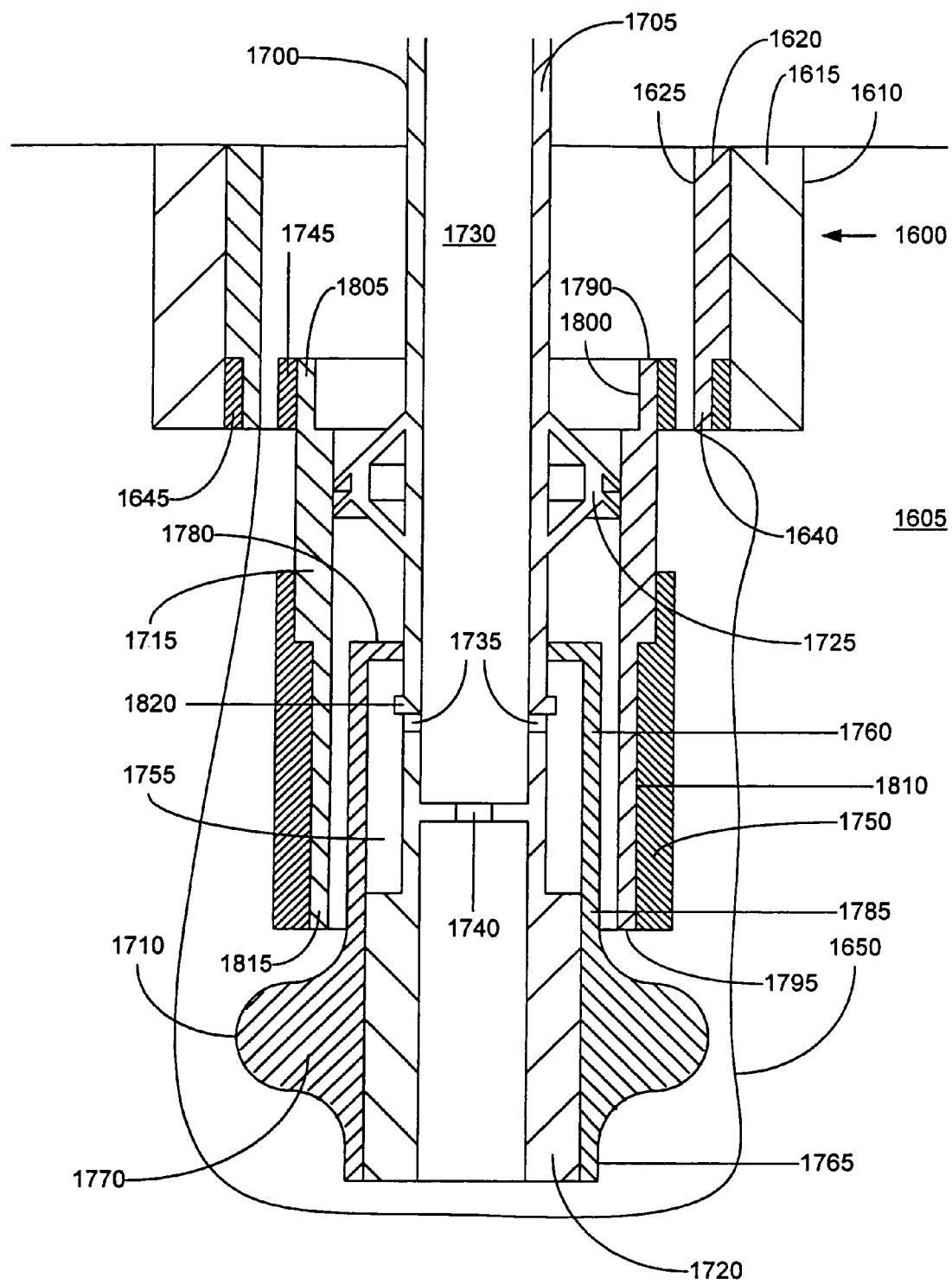


FIGURE 14c

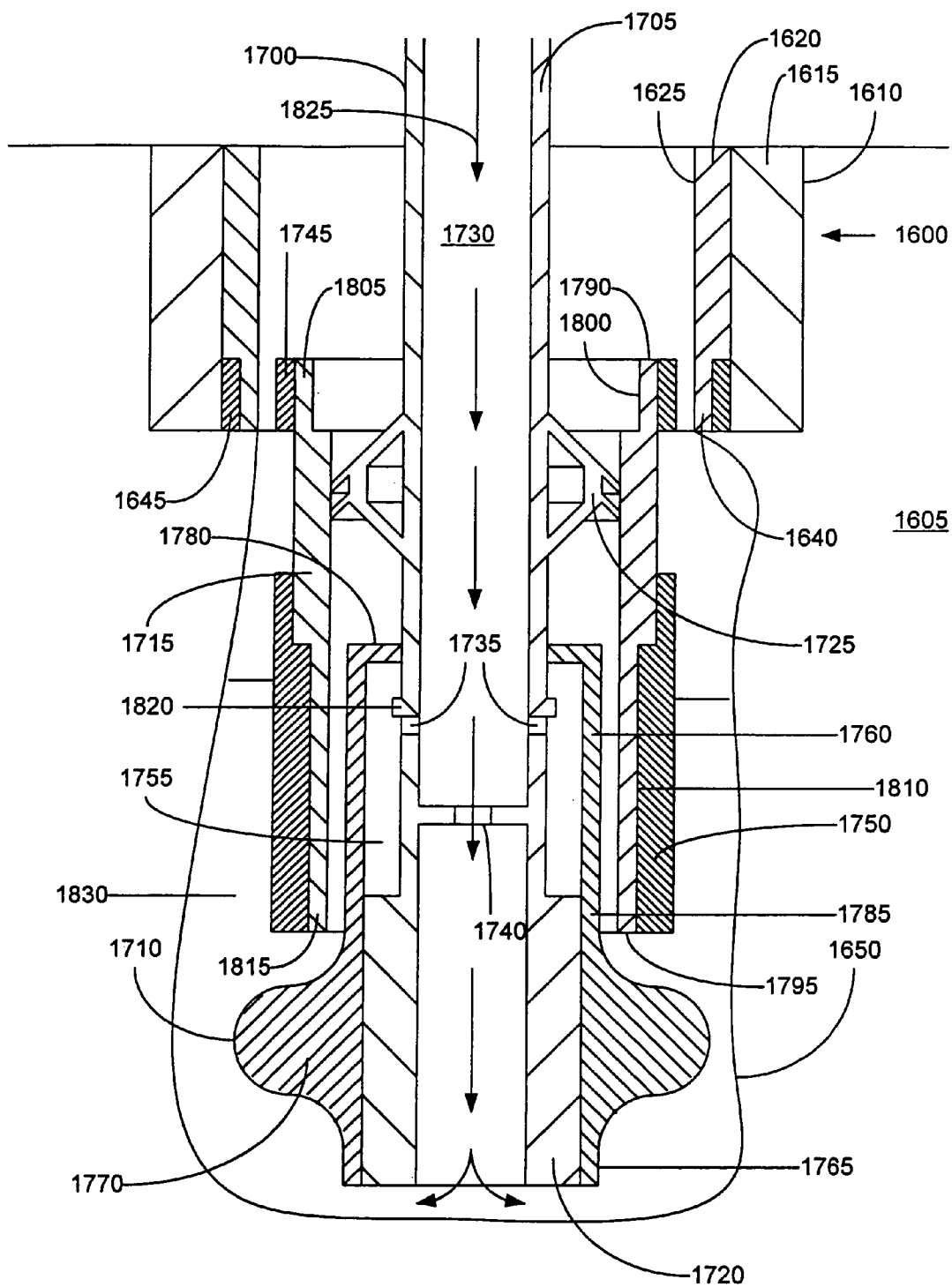


FIGURE 14d

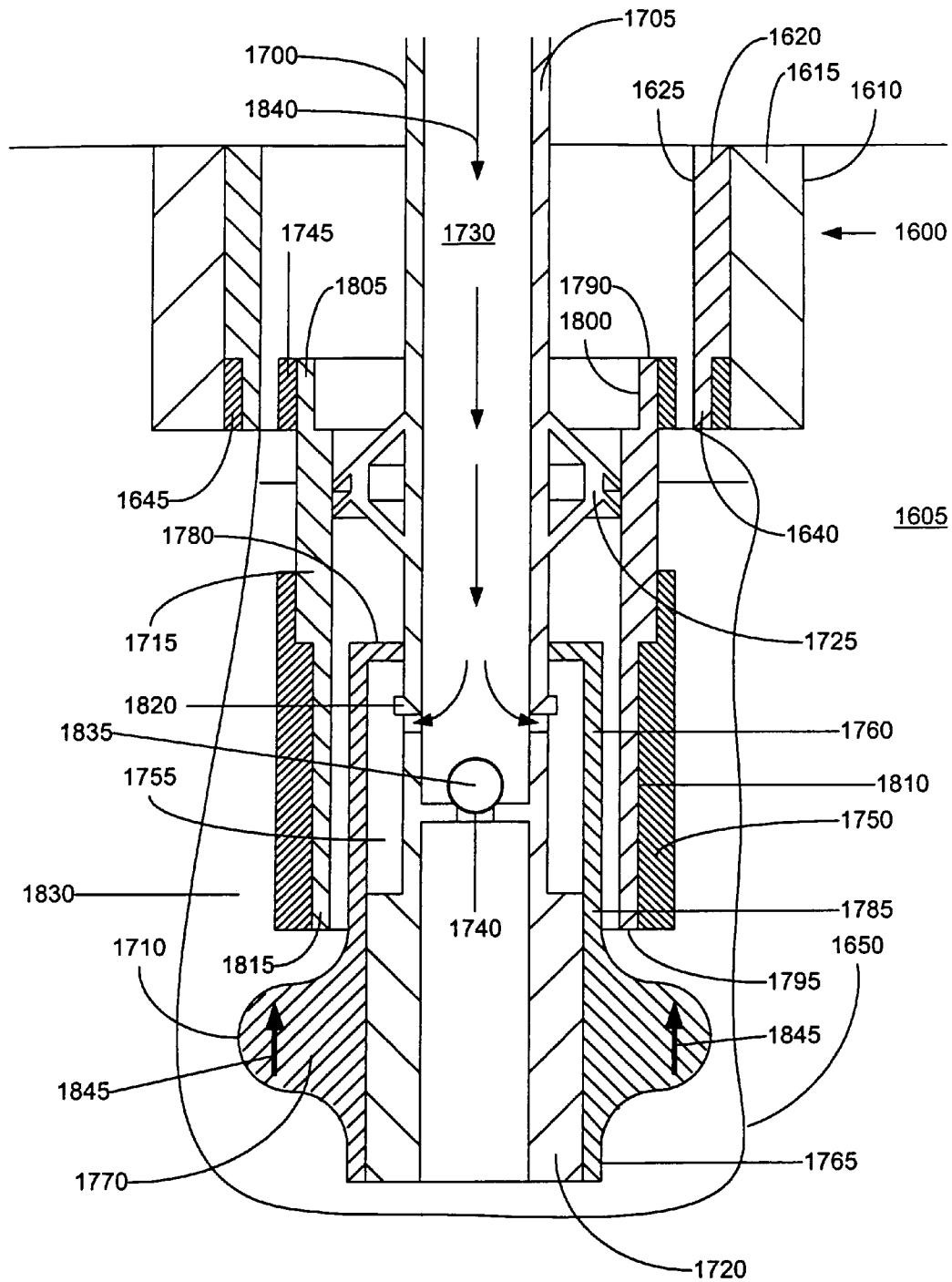


FIGURE 14e

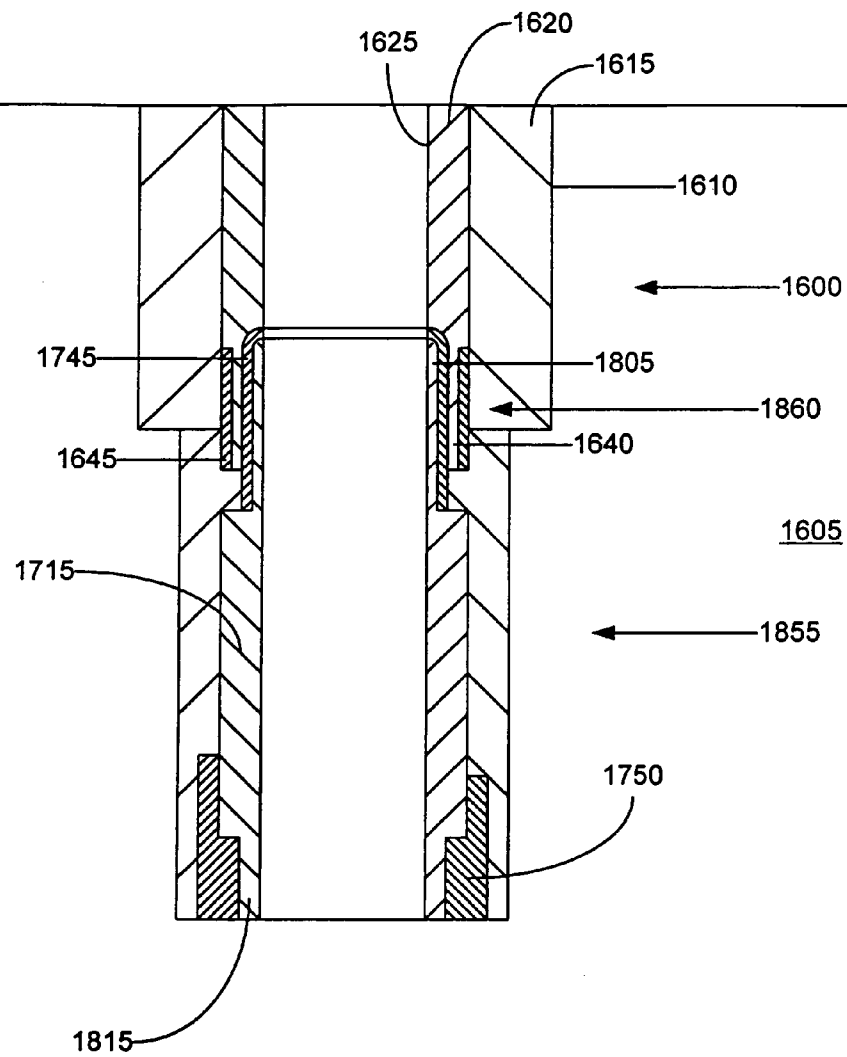


FIGURE 14f

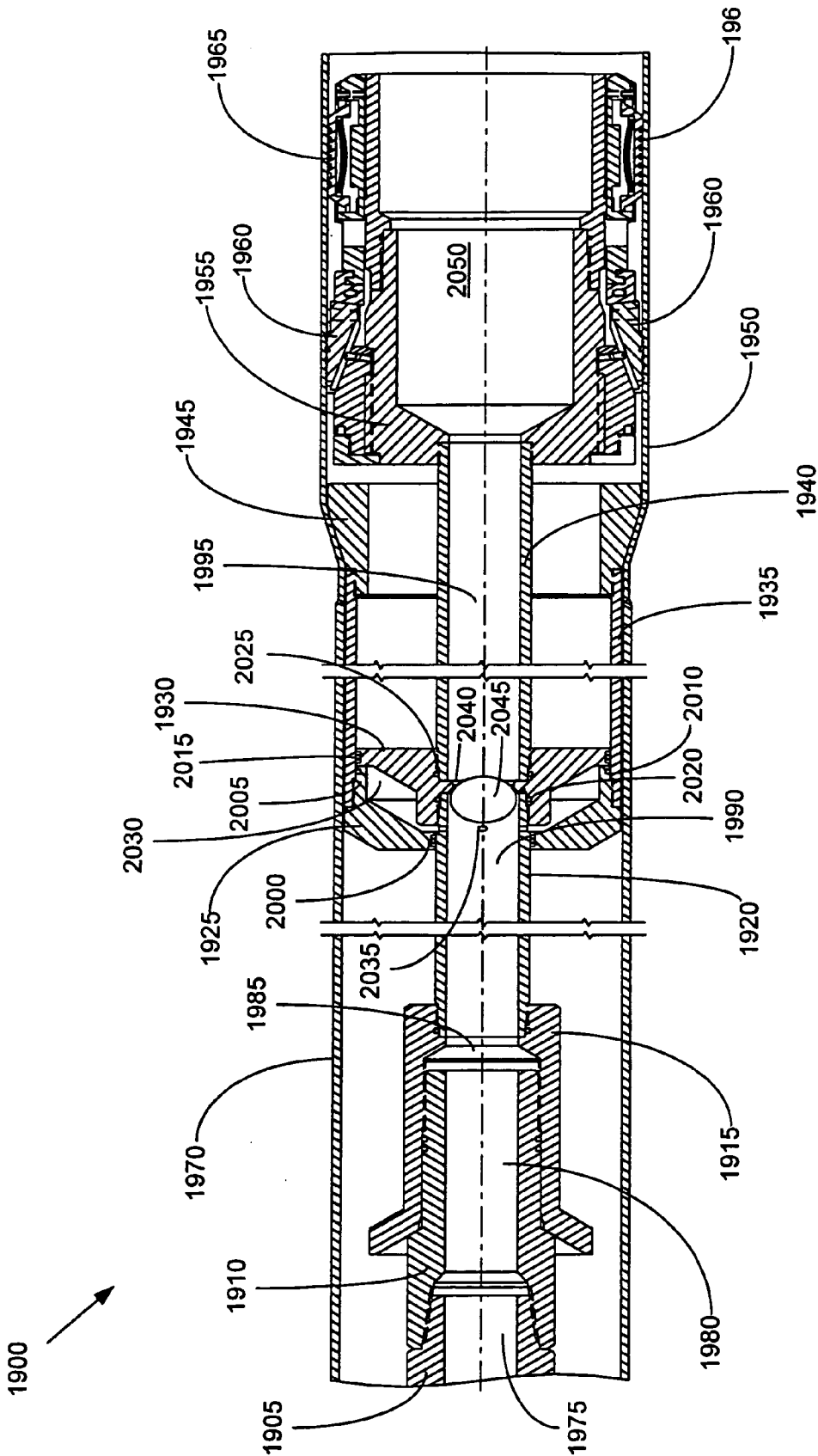
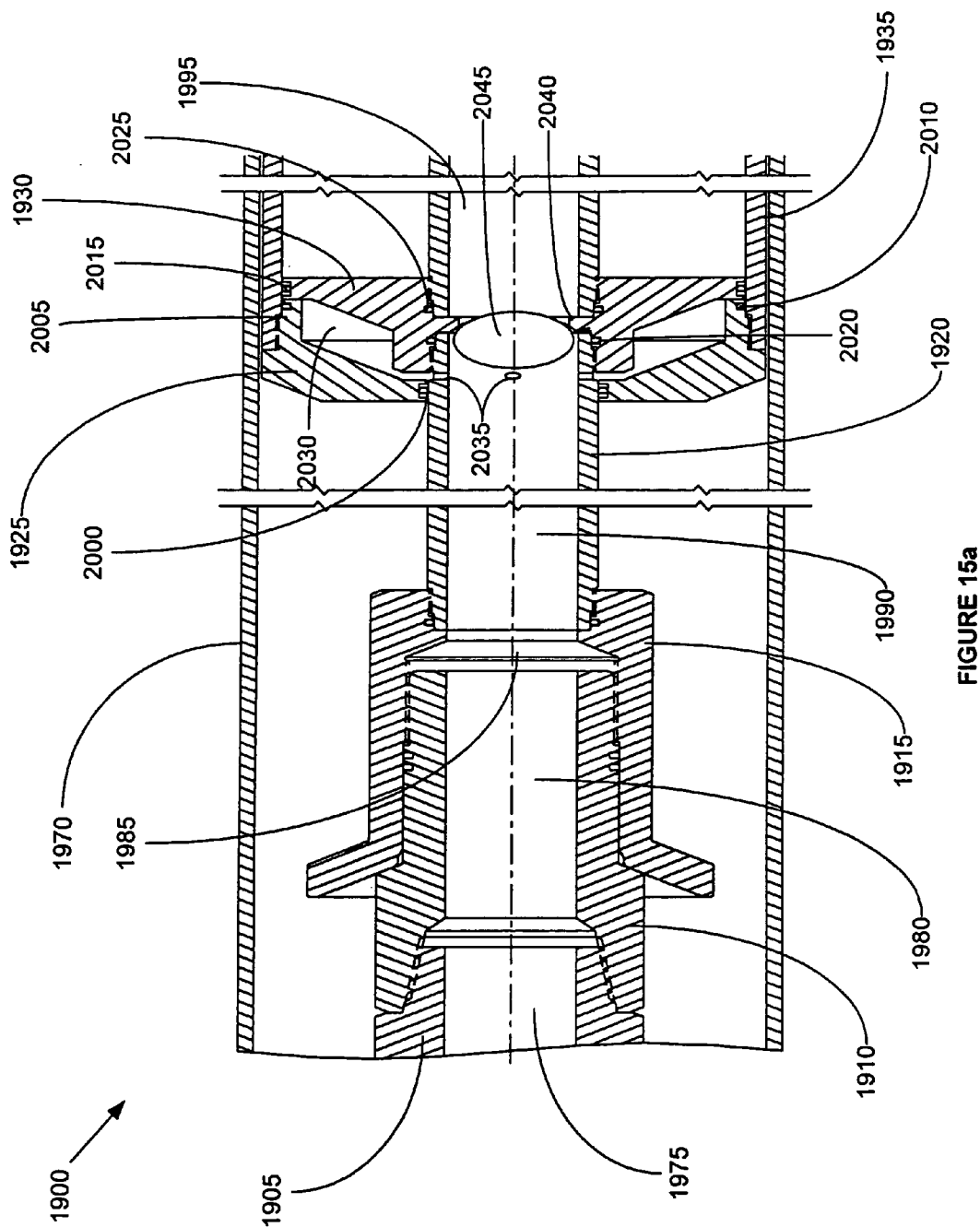
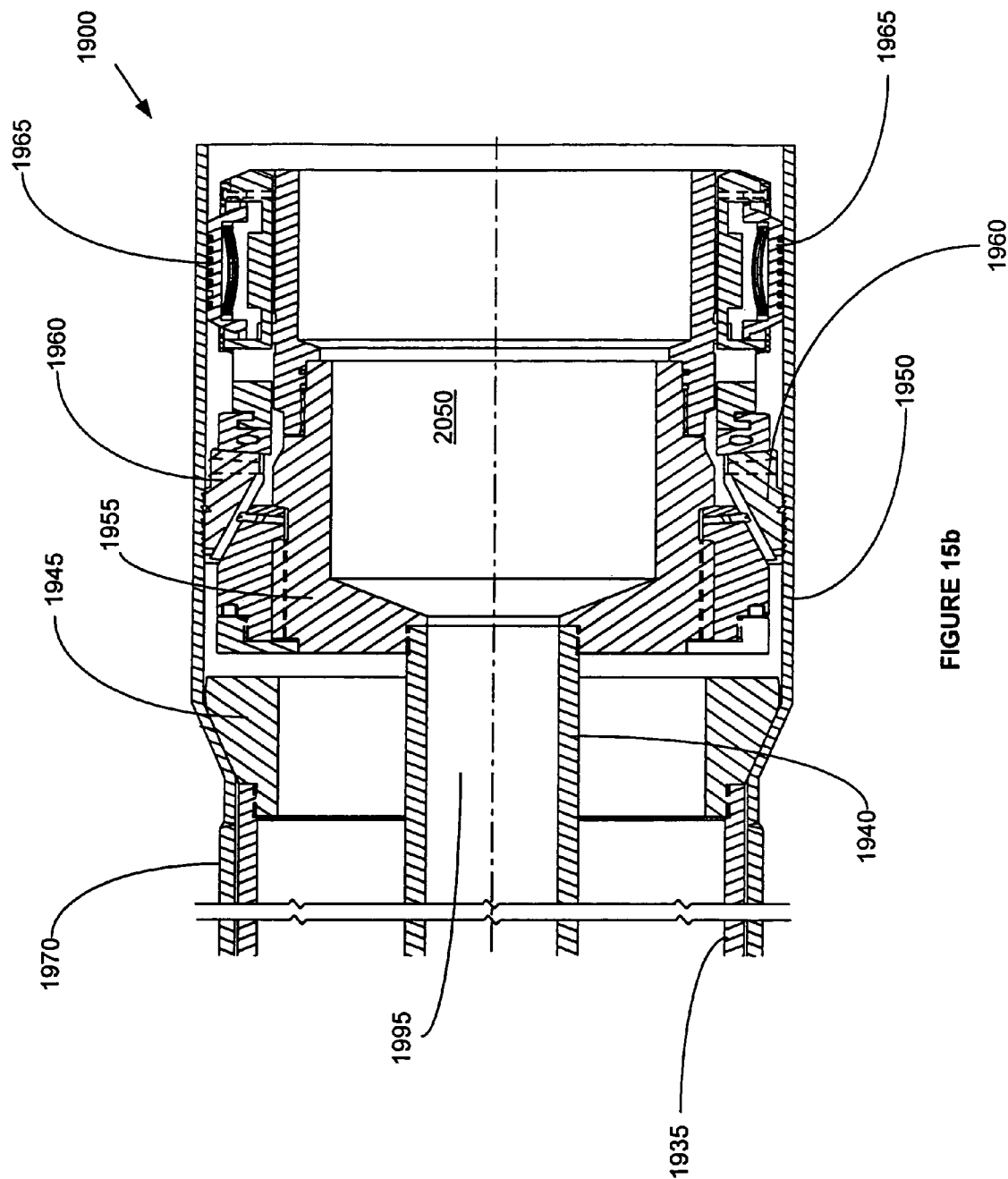
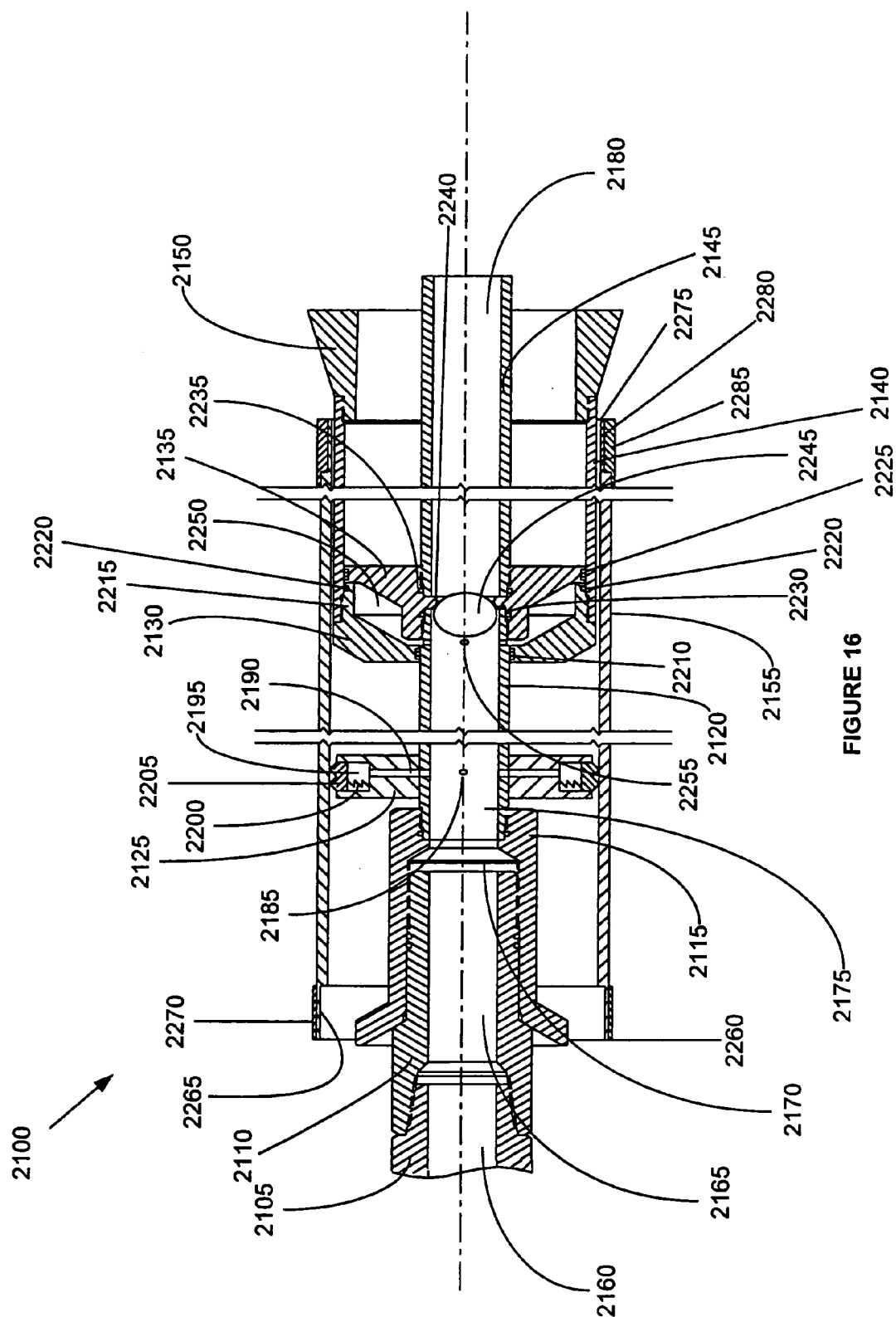


FIGURE 15







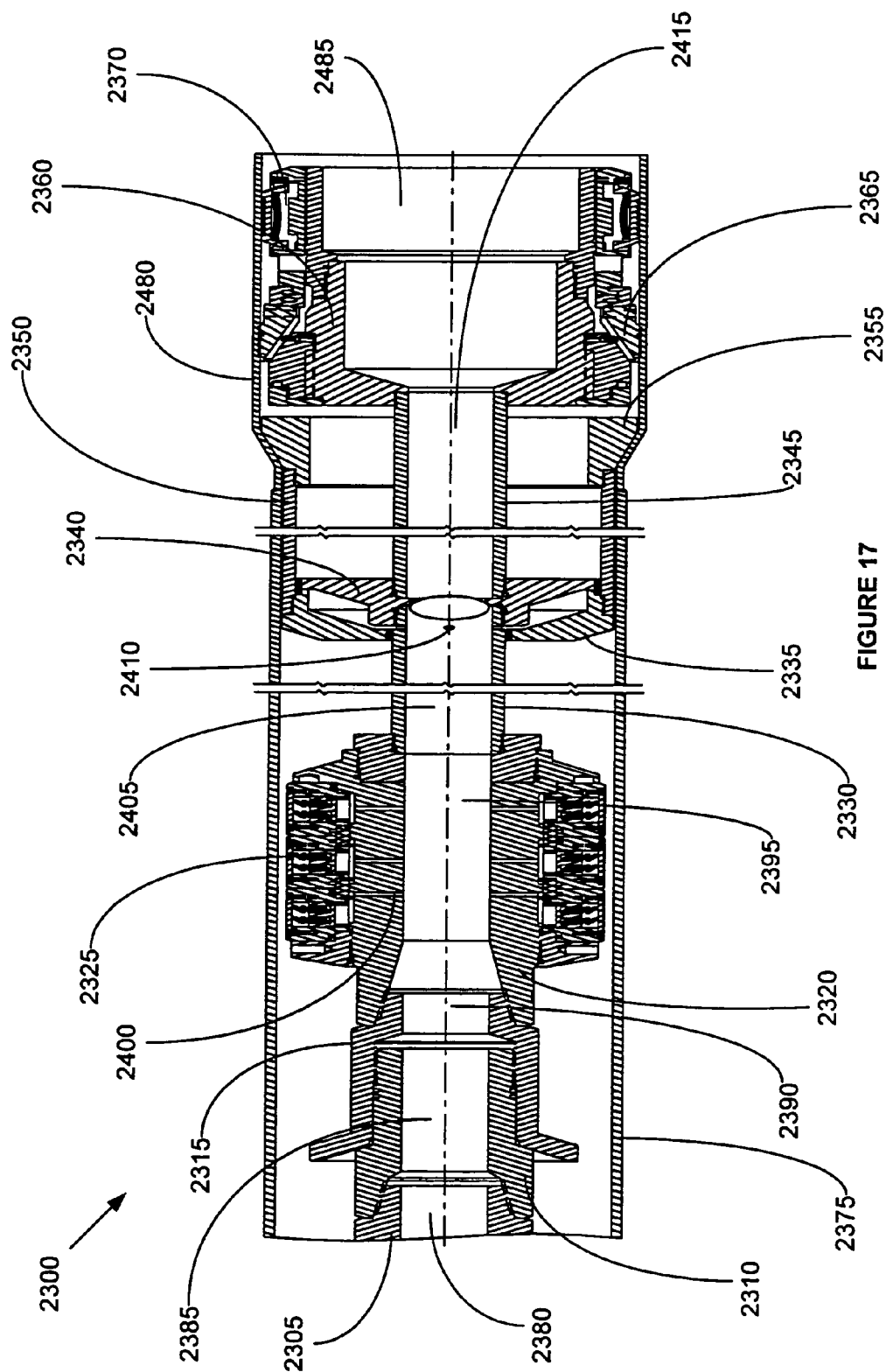


FIGURE 17

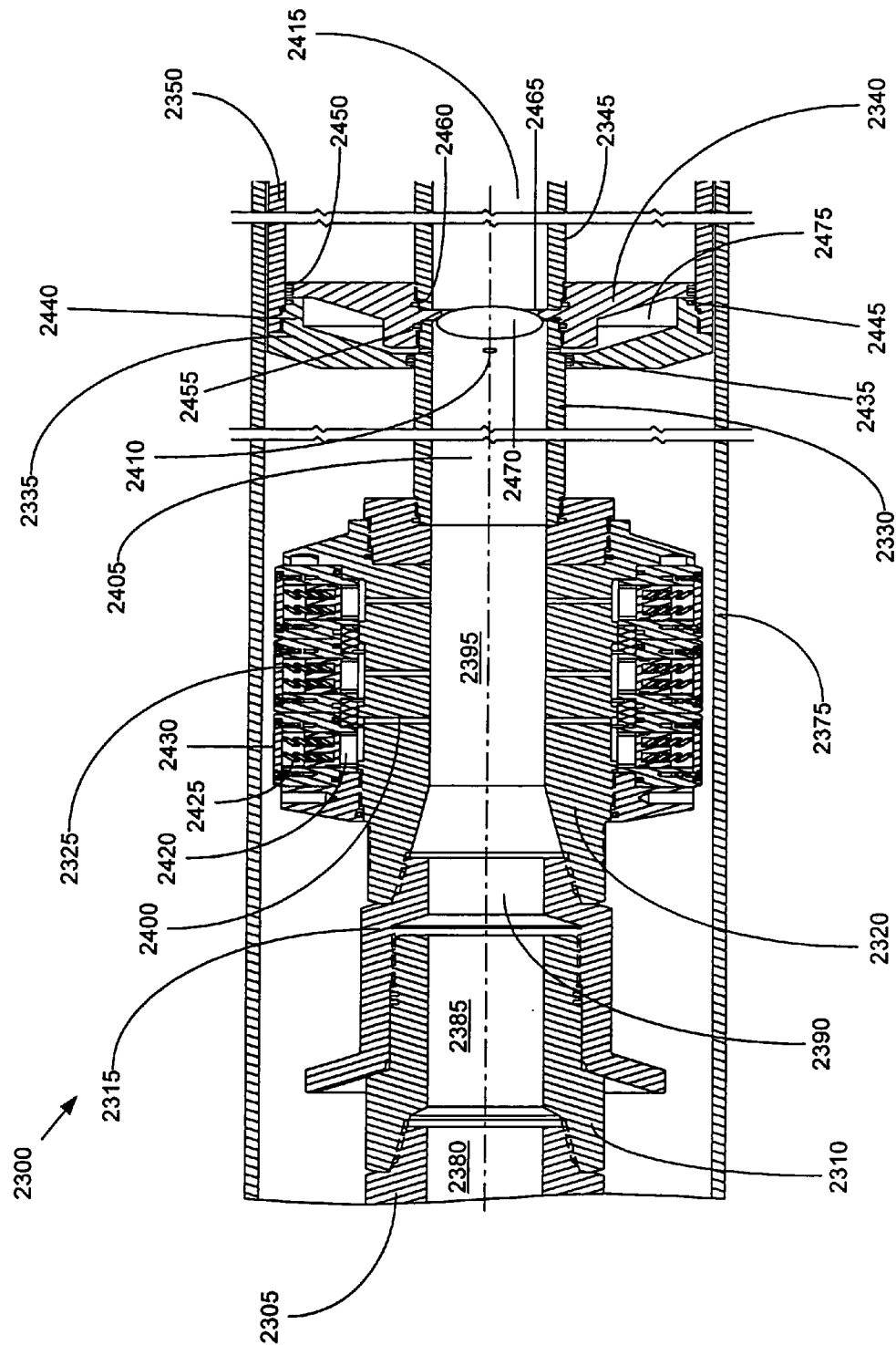


FIGURE 17a

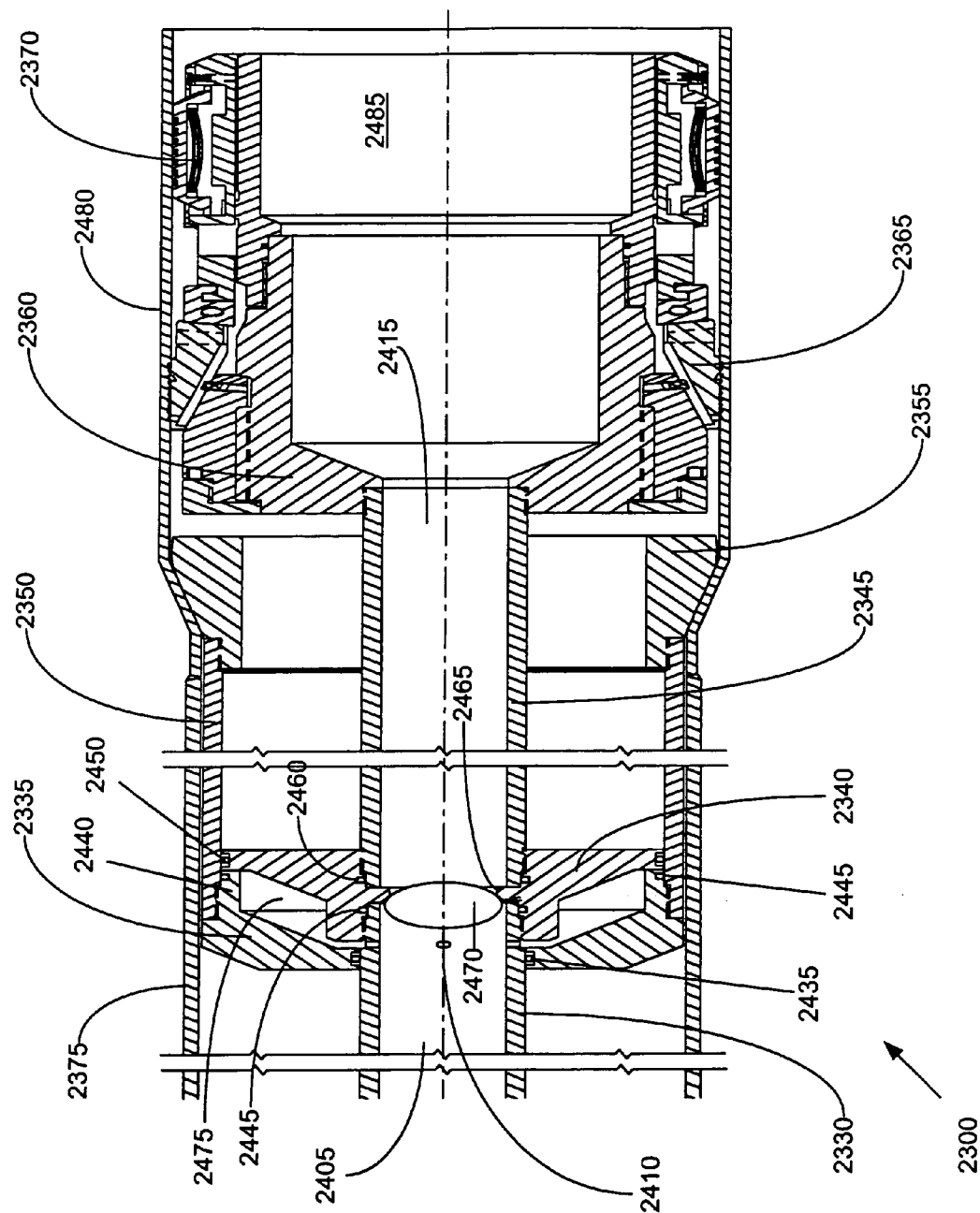
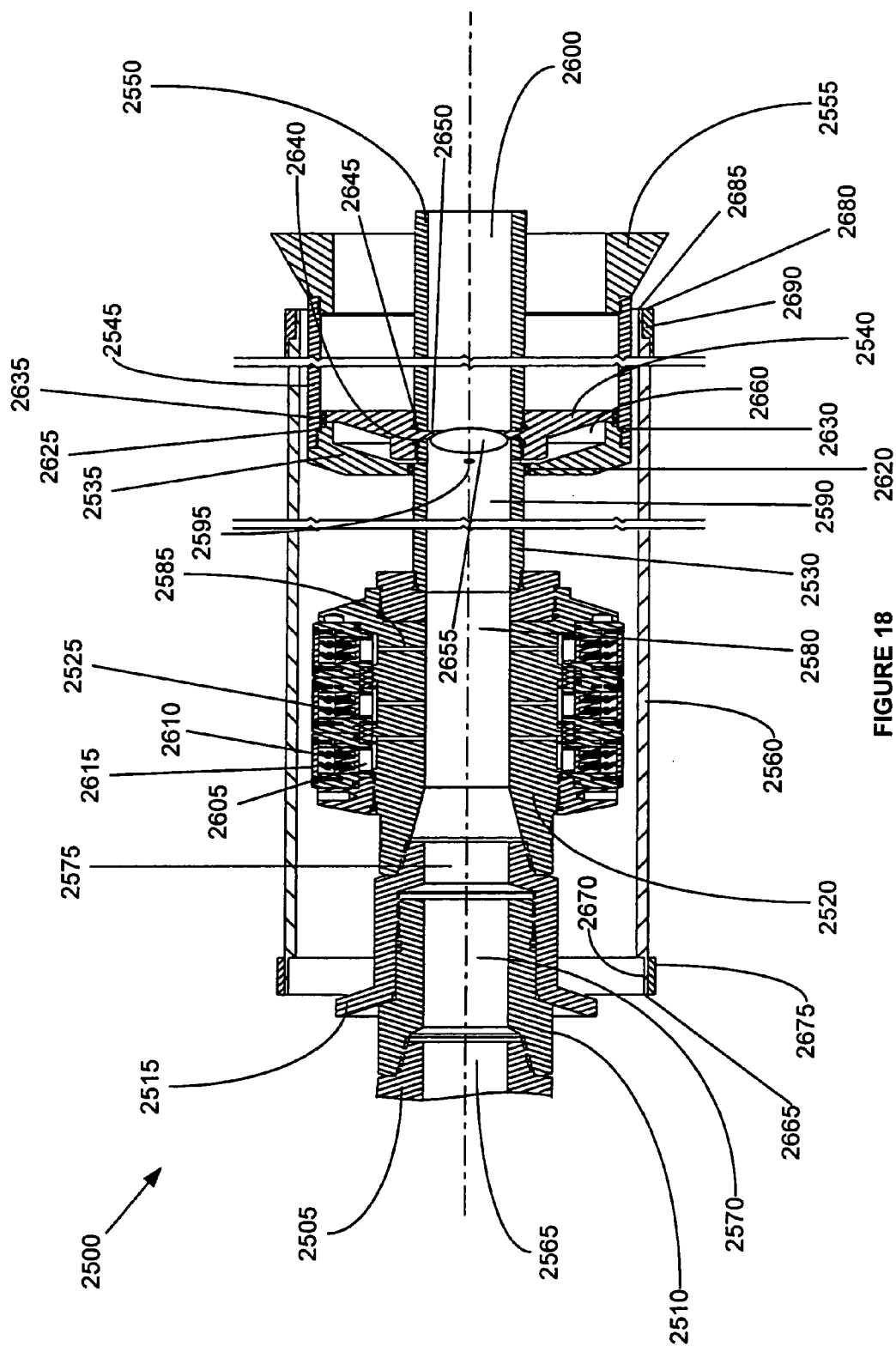
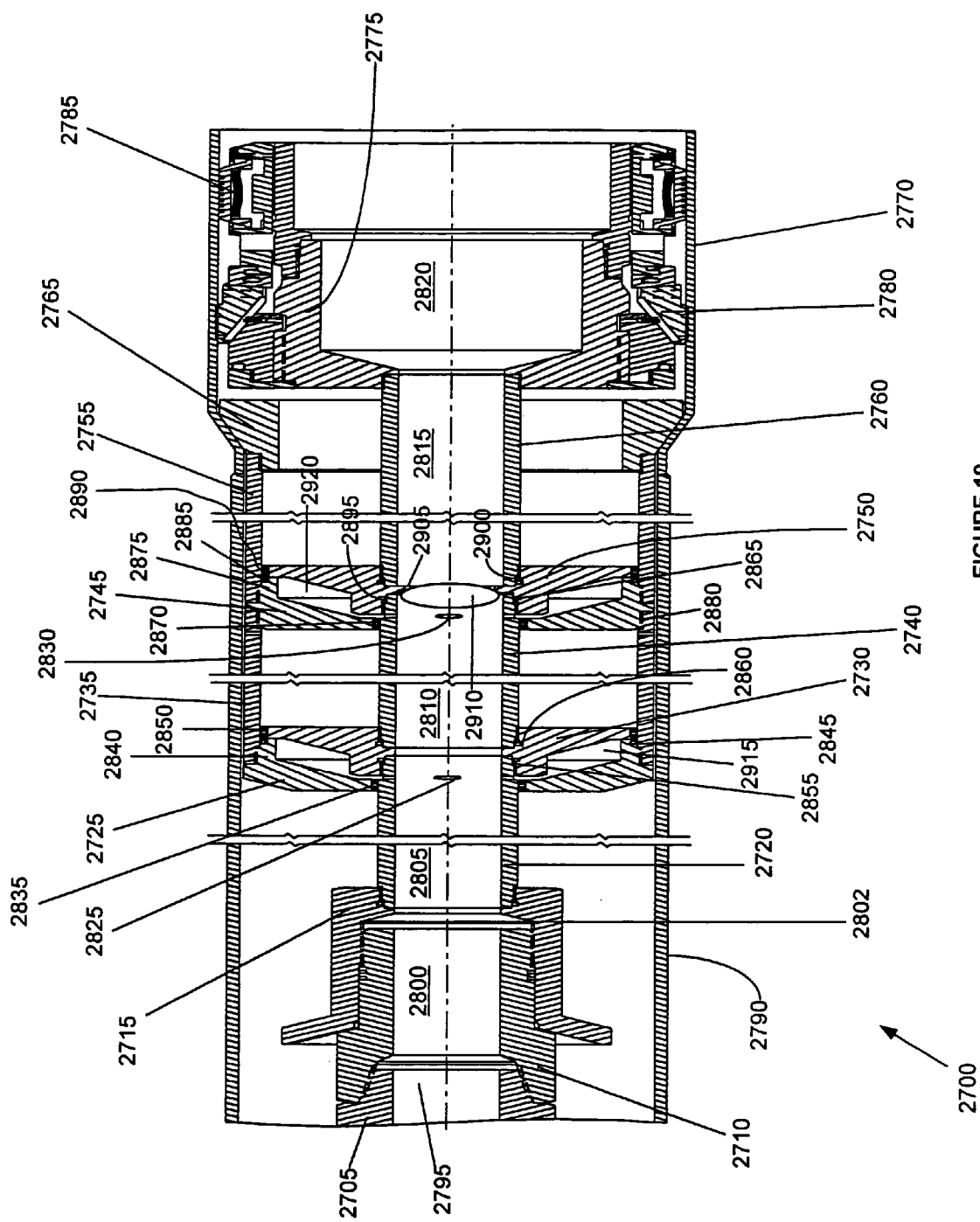
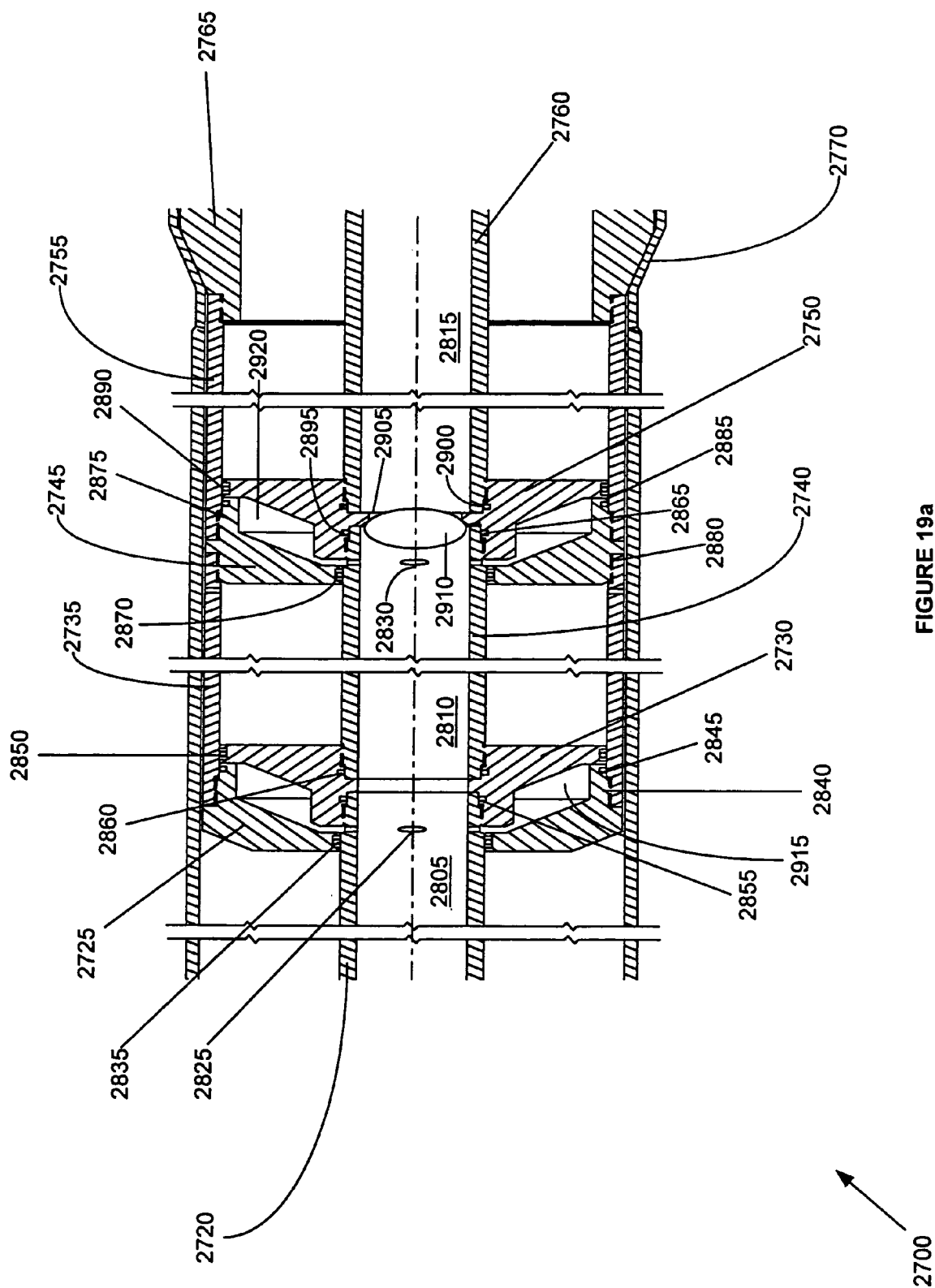


FIGURE 17b







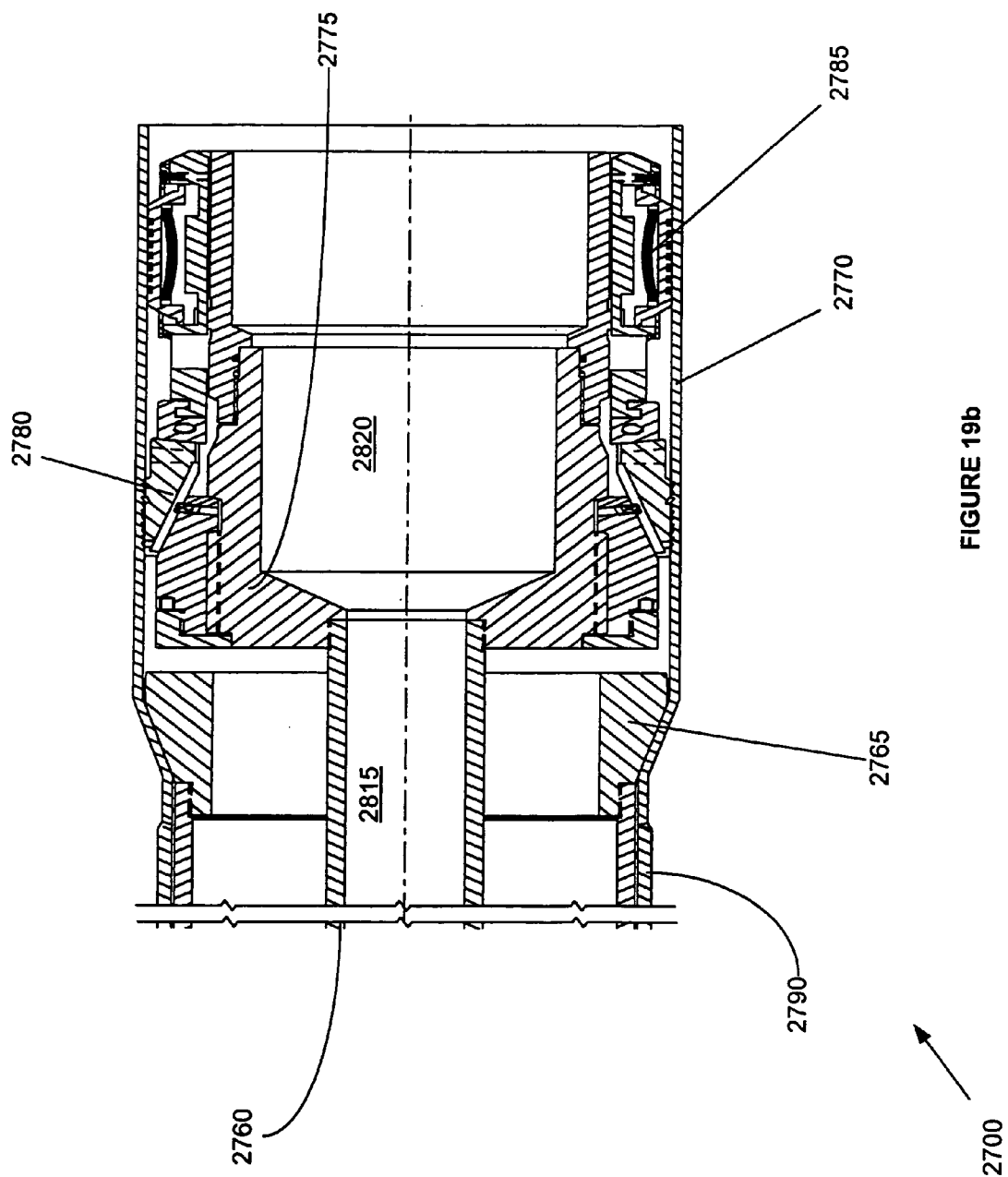
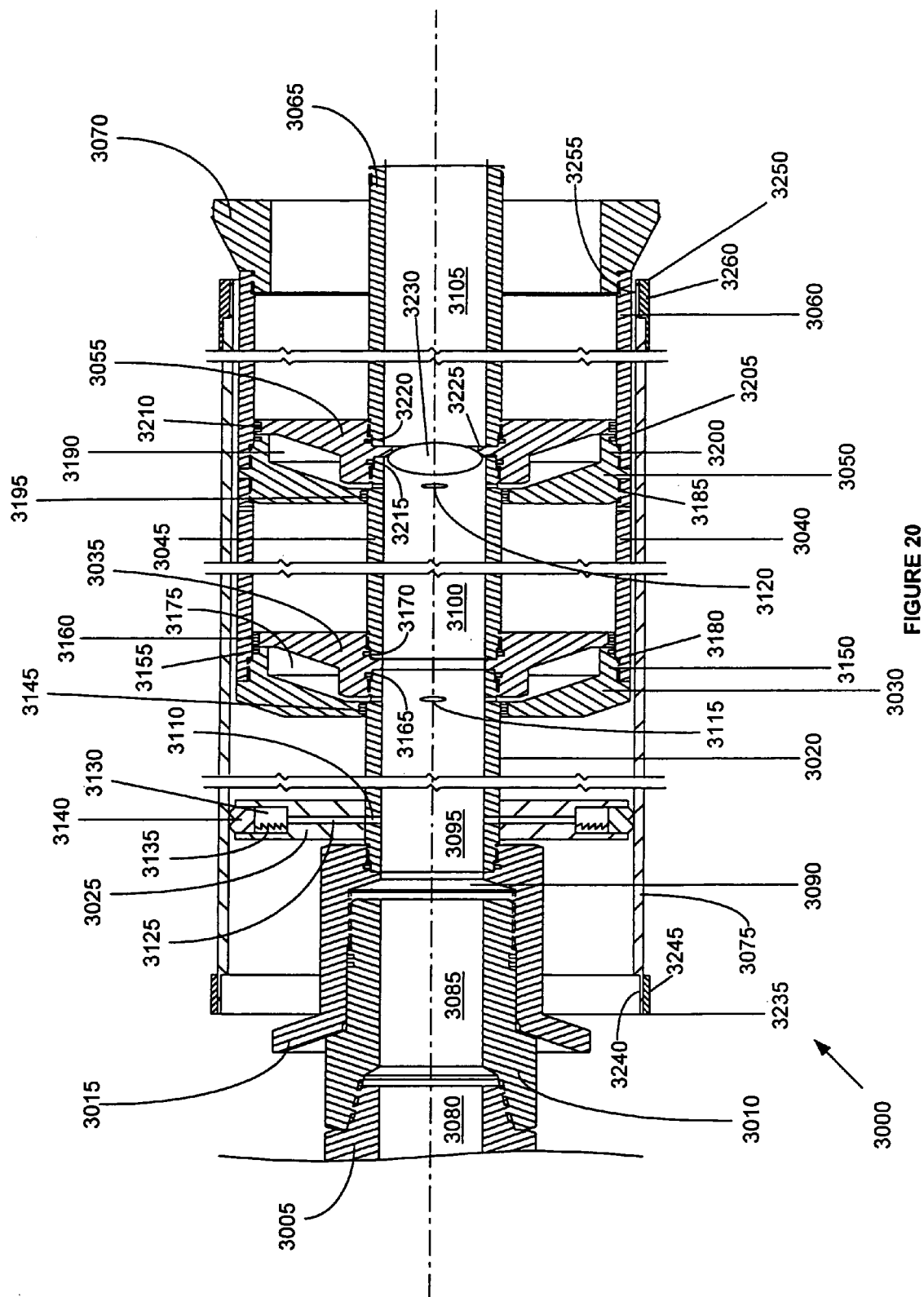


FIGURE 19b



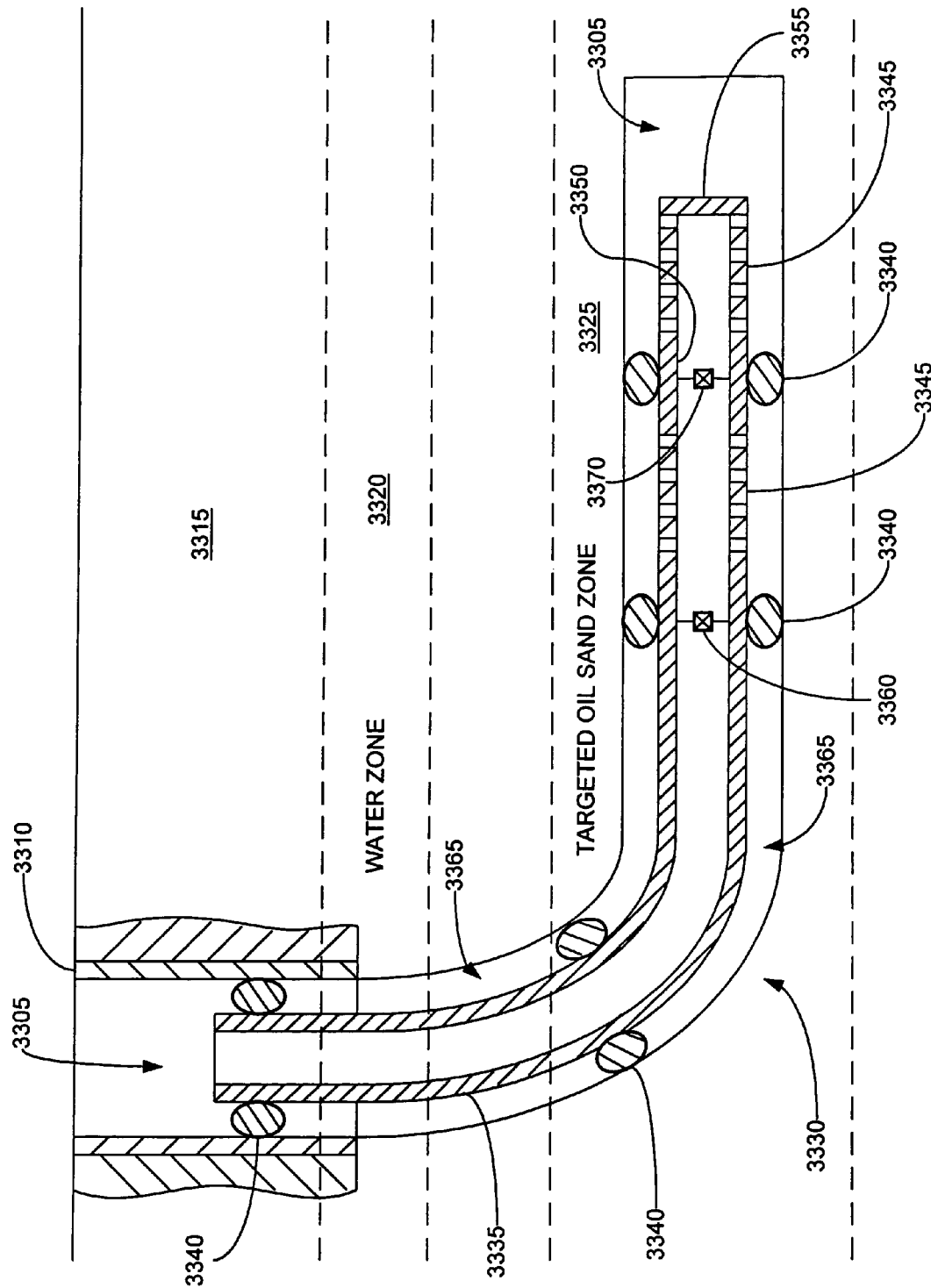


FIGURE 21

METHOD OF CREATING A CASING IN A BOREHOLE

CROSS REFERENCE TO RELATED APPLICATIONS

This application is a division of U.S. utility patent application Ser. No. 09/510,913, filed on Feb. 23, 2000, that claimed the benefit of the filing date of U.S. Provisional Patent Application Ser. No. 60/121,702, filed on Feb. 25, 1999, that was a continuation in part of U.S. utility patent application Ser. No. 09/502,350, filed on Feb. 10, 2000 now U.S. Pat. No. 6,823,937, which claimed the benefit of the filing date of U.S. provisional patent application Ser. No. 60/119,611, filed on Feb. 11, 1999, which was a continuation in part of U.S. utility patent application Ser. No. 09/454,139, filed on Dec. 3, 1999 now U.S. Pat. No. 6,497,289, which claimed the benefit of the filing date of U.S. provisional patent application Ser. No. 60/111,293, filed on Dec. 7, 1998, the disclosures of which are incorporated herein by reference.

This application is related to the following applications: (1) U.S. Pat. No. 6,497,289, which was filed as U.S. patent application Ser. No. 09/454,139, filed on Dec. 3, 1999, which claims priority from provisional application 60/111,293, filed on Dec. 7, 1998, (2) U.S. patent application Ser. No. 09/510,913, filed on Feb. 23, 2000, which claims priority from provisional application 60/121,702, filed on Feb. 25, 1999, (3) U.S. patent application Ser. No. 09/502,350, filed on Feb. 10, 2000, which claims priority from provisional application 60/119,611, filed on Feb. 11, 1999, (4) U.S. Pat. No. 6,328,113, which was filed as U.S. patent application Ser. No. 09/440,338, filed on Nov. 15, 1999, which claims priority from provisional application 60/108,558, filed on Nov. 16, 1998, (5) U.S. patent application Ser. No. 10/169,434, filed on Jul. 1, 2002, which claims priority from provisional application 60/183,546, filed on Feb. 18, 2000, (6) U.S. patent application Ser. No. 09/523,468, filed on Mar. 10, 2000, (now U.S. Pat. No. 6,640,903 which issued Nov. 4, 2003), which claims priority from provisional application 60/124,042, filed on Mar. 11, 1999, (7) U.S. Pat. No. 6,568,471, which was filed as patent application Ser. No. 09/512,895, filed on Feb. 24, 2000, which claims priority from provisional application 60/121,841, filed on Feb. 26, 1999, (8) U.S. Pat. No. 6,575,240, which was filed as patent application Ser. No. 09/511,941, filed on Feb. 24, 2000, which claims priority from provisional application 60/121,907, filed on Feb. 26, 1999, (9) U.S. Pat. No. 6,557,640, which was filed as patent application Ser. No. 09/588,946, filed on Jun. 7, 2000, which claims priority from provisional application 60/137,998, filed on Jun. 7, 1999, (10) U.S. patent application Ser. No. 09/981,916, filed on Oct. 18, 2001 as a continuation-in-part application of U.S. Pat. No. 6,328,113, which was filed as U.S. patent application Ser. No. 09/440,338, filed on Nov. 15, 1999, which claims priority from provisional application 60/108,558, filed on Nov. 16, 1998, (11) U.S. Pat. No. 6,604,763, which was filed as application Ser. No. 09/559,122, filed on Apr. 26, 2000, which claims priority from provisional application 60/131,106, filed on Apr. 26, 1999, (12) U.S. patent application Ser. No. 10/030,593, filed on Jan. 8, 2002, which claims priority from provisional application 60/146,203, filed on Jul. 29, 1999, (13) U.S. provisional patent application Ser. No. 60/143,039, filed on Jul. 9, 1999, (14) U.S. patent application Ser. No. 10/111,982, filed on Apr. 30, 2002, which claims priority from provisional patent application Ser. No. 60/162,671, filed on Nov. 1, 1999, (15) U.S.

provisional patent application Ser. No. 60/154,047, filed on Sep. 16, 1999, (16) U.S. provisional patent application Ser. No. 60/438,828, filed on Jan. 9, 2003, (17) U.S. Pat. No. 6,564,875, which was filed as application Ser. No. 09/679,907, on Oct. 5, 2000, which claims priority from provisional patent application Ser. No. 60/159,082, filed on Oct. 12, 1999, (18) U.S. patent application Ser. No. 10/089,419, filed on Mar. 27, 2002, which claims priority from provisional patent application Ser. No. 60/159,039, filed on Oct. 12, 1999, (19) U.S. patent application Ser. No. 09/679,906, filed on Oct. 5, 2000, which claims priority from provisional patent application Ser. No. 60/159,033, filed on Oct. 12, 1999, (20) U.S. patent application Ser. No. 10/303,992, filed on Nov. 22, 2002, which claims priority from provisional patent application Ser. No. 60/212,359, filed on Jun. 19, 2000, (21) U.S. provisional patent application Ser. No. 60/165,228, filed on Nov. 12, 1999, (22) U.S. provisional patent application Ser. No. 60/455,051, filed on Mar. 14, 2003, (23) PCT application US02/2477, filed on Jun. 26, 2002, which claims priority from U.S. provisional patent application Ser. No. 60/303,711, filed on Jul. 6, 2001, (24) U.S. patent application Ser. No. 10/311,412, filed on Dec. 12, 2002, which claims priority from provisional patent application Ser. No. 60/221,443, filed on Jul. 28, 2000, (25) U.S. patent application Ser. No. 10/322,947, filed on Dec. 18, 2002, which claims priority from provisional patent application Ser. No. 60/221,645, filed on Jul. 28, 2000, (26) U.S. patent application Ser. No. 10/322,947, filed on Jan. 22, 2003, which claims priority from provisional patent application Ser. No. 60/233,638, filed on Sep. 18, 2000, (27) U.S. patent application Ser. No. 10/406,648, filed on Mar. 31, 2003, which claims priority from provisional patent application Ser. No. 60/237,334, filed on Oct. 2, 2000, (28) PCT application US02/04353, filed on Feb. 14, 2002, which claims priority from U.S. provisional patent application Ser. No. 60/270,007, filed on Feb. 20, 2001, (29) U.S. patent application Ser. No. 10/465,835, filed on Jun. 13, 2003, which claims priority from provisional patent application Ser. No. 60/262,434, filed on Jan. 17, 2001, (30) U.S. patent application Ser. No. 10/465,831, filed on Jun. 13, 2003, which claims priority from U.S. provisional patent application Ser. No. 60/259,486, filed on Jan. 3, 2001, (31) U.S. provisional patent application Ser. No. 60/452,303, filed on Mar. 5, 2003, (32) U.S. Pat. No. 6,470,966, which was filed as patent application Ser. No. 09/850,093, filed on May 7, 2001, as a divisional application of U.S. Pat. No. 6,497,289, which was filed as U.S. patent application Ser. No. 09/454,139, filed on Dec. 3, 1999, which claims priority from provisional application 60/111,293, filed on Dec. 7, 1998, (33) U.S. Pat. No. 6,561,227, which was filed as patent application Ser. No. 09/852,026, filed on May 9, 2001, as a divisional application of U.S. Pat. No. 6,497,289, which was filed as U.S. patent application Ser. No. 09/454,139, filed on Dec. 3, 1999, which claims priority from provisional application 60/111,293, filed on Dec. 7, 1998, (34) U.S. patent application Ser. No. 09/852,027, filed on May 9, 2001, as a divisional application of U.S. Pat. No. 6,497,289, which was filed as U.S. patent application Ser. No. 09/454,139, filed on Dec. 3, 1999, which claims priority from provisional application 60/111,293, filed on Dec. 7, 1998, (35) PCT Application US02/25608, filed on Aug. 13, 2002, which claims priority from provisional application 60/318,021, filed on Sep. 7, 2001, (36) PCT Application US02/24399, filed on Aug. 1, 2002, which claims priority from U.S. provisional patent application Ser. No. 60/313,453, filed on Aug. 20, 2001, (37) PCT Application US02/29856, filed on Sep. 19, 2002, which claims priority from U.S. provisional patent

application Ser. No. 60/326,886, filed on Oct. 3, 2001, (38) PCT Application US02/20256, filed on Jun. 26, 2002, which claims priority from U.S. provisional patent application Ser. No. 60/303,740, filed on Jul. 6, 2001, (39) U.S. patent application Ser. No. 09/962,469, filed on Sep. 25, 2001, which is a divisional of U.S. patent application Ser. No. 09/523,468, filed on Mar. 10, 2000, (now U.S. Pat. No. 6,640,903 which issued Nov. 4, 2003), which claims priority from provisional application 60/124,042, filed on Mar. 11, 1999, (40) U.S. patent application Ser. No. 09/962,470, filed on Sep. 25, 2001, which is a divisional of U.S. patent application Ser. No. 09/523,468, filed on Mar. 10, 2000, (now U.S. Pat. No. 6,640,903 which issued Nov. 4, 2003), which claims priority from provisional application 60/124,042, filed on Mar. 11, 1999, (41) U.S. patent application Ser. No. 09/962,471, filed on Sep. 25, 2001, which is a divisional of U.S. patent application Ser. No. 09/523,468, filed on Mar. 10, 2000, (now U.S. Pat. No. 6,640,903 which issued Nov. 4, 2003), which claims priority from provisional application 60/124,042, filed on Mar. 11, 1999, (42) U.S. patent application Ser. No. 09/962,467, filed on Sep. 25, 2001, which is a divisional of U.S. patent application Ser. No. 09/523,468, filed on Mar. 10, 2000, (now U.S. Pat. No. 6,640,903 which issued Nov. 4, 2003), which claims priority from provisional application 60/124,042, filed on Mar. 11, 1999, (43) U.S. patent application Ser. No. 09/962,468, filed on Sep. 25, 2001, which is a divisional of U.S. patent application Ser. No. 09/523,468, filed on Mar. 10, 2000, (now U.S. Pat. No. 6,640,903 which issued Nov. 4, 2003), which claims priority from provisional application 60/124,042, filed on Mar. 11, 1999, (44) PCT application US 02/25727, filed on Aug. 14, 2002, which claims priority from U.S. provisional patent application Ser. No. 60/317,985, filed on Sep. 6, 2001, and U.S. provisional patent application Ser. No. 60/318,386, filed on Sep. 10, 2001, (45) PCT application US 02/39425, filed on Dec. 10, 2002, which claims priority from U.S. provisional patent application Ser. No. 60/343,674, filed on Dec. 27, 2001, (46) U.S. utility patent application Ser. No. 09/969,922, filed on Oct. 3, 2001, (now U.S. Pat. No. 6,634,431 which issued Oct. 21, 2003), which is a continuation-in-part application of U.S. Pat. No. 6,328,113, which was filed as U.S. patent application Ser. No. 09/440,338, filed on Nov. 15, 1999, which claims priority from provisional application 60/108,558, filed on Nov. 16, 1998, (47) U.S. utility patent application Ser. No. 10/516,467, filed on Dec. 10, 2001, which is a continuation application of U.S. utility patent application Ser. No. 09/969,922, filed on Oct. 3, 2001, (now U.S. Pat. No. 6,634,431 which issued Oct. 21, 2003), which is a continuation-in-part application of U.S. Pat. No. 6,328,113, which was filed as U.S. patent application Ser. No. 09/440,338, filed on Nov. 15, 1999, which claims priority from provisional application 60/108,558, filed on Nov. 16, 1998, (48) PCT application US 03/00609, filed on Jan. 9, 2003, which claims priority from U.S. provisional patent application Ser. No. 60/357,372, filed on Feb. 15, 2002, (49) U.S. patent application Ser. No. 10/074,703, filed on Feb. 12, 2002, which is a divisional of U.S. Pat. No. 6,568,471, which was filed as patent application Ser. No. 09/512,895, filed on Feb. 24, 2000, which claims priority from provisional application 60/121,841, filed on Feb. 26, 1999, (50) U.S. patent application Ser. No. 10/074,244, filed on Feb. 12, 2002, which is a divisional of U.S. Pat. No. 6,568,471, which was filed as patent application Ser. No. 09/512,895, filed on Feb. 24, 2000, which claims priority from provisional application 60/121,841, filed on Feb. 26, 1999, (51) U.S. patent application Ser. No. 10/076,660, filed on Feb. 15, 2002, which is a divisional of U.S. Pat.

No. 6,568,471, which was filed as patent application Ser. No. 09/512,895, filed on Feb. 24, 2000, which claims priority from provisional application 60/121,841, filed on Feb. 26, 1999, (52) U.S. patent application Ser. No. 10/076,661, filed on Feb. 15, 2002, which is a divisional of U.S. Pat. No. 6,568,471, which was filed as patent application Ser. No. 09/512,895, filed on Feb. 24, 2000, which claims priority from provisional application 60/121,841, filed on Feb. 26, 1999, (53) U.S. patent application Ser. No. 10/076,659, filed on Feb. 15, 2002, which is a divisional of U.S. Pat. No. 6,568,471, which was filed as patent application Ser. No. 09/512,895, filed on Feb. 24, 2000, which claims priority from provisional application 60/121,841, filed on Feb. 26, 1999, (54) U.S. patent application Ser. No. 10/078,928, filed on Feb. 20, 2002, which is a divisional of U.S. Pat. No. 6,568,471, which was filed as patent application Ser. No. 09/512,895, filed on Feb. 24, 2000, which claims priority from provisional application 60/121,841, filed on Feb. 26, 1999, (55) U.S. patent application Ser. No. 10/078,922, filed on Feb. 20, 2002, which is a divisional of U.S. Pat. No. 6,568,471, which was filed as patent application Ser. No. 09/512,895, filed on Feb. 24, 2000, which claims priority from provisional application 60/121,841, filed on Feb. 26, 1999, (56) U.S. patent application Ser. No. 10/078,921, filed on Feb. 20, 2002, which is a divisional of U.S. Pat. No. 6,568,471, which was filed as patent application Ser. No. 09/512,895, filed on Feb. 24, 2000, which claims priority from provisional application 60/121,841, filed on Feb. 26, 1999, (57) U.S. patent application Ser. No. 10/261,928, filed on Oct. 1, 2002, which is a divisional of U.S. Pat. No. 6,557,640, which was filed as patent application Ser. No. 09/588,946, filed on Jun. 7, 2000, which claims priority from provisional application 60/137,998, filed on Jun. 7, 1999, (58) U.S. patent application Ser. No. 10/079,276, filed on Feb. 20, 2002, which is a divisional of U.S. Pat. No. 6,568,471, which was filed as patent application Ser. No. 09/512,895, filed on Feb. 24, 2000, which claims priority from provisional application 60/121,841, filed on Feb. 26, 1999, (59) U.S. patent application Ser. No. 10/262,009, filed on Oct. 1, 2002, which is a divisional of U.S. Pat. No. 6,557,640, which was filed as patent application Ser. No. 09/588,946, filed on Jun. 7, 2000, which claims priority from provisional application 60/137,998, filed on Jun. 7, 1999, (60) U.S. patent application Ser. No. 10/092,481, filed on Mar. 7, 2002, which is a divisional of U.S. Pat. No. 6,568,471, which was filed as patent application Ser. No. 09/512,895, filed on Feb. 24, 2000, which claims priority from provisional application 60/121,841, filed on Feb. 26, 1999, (61) U.S. patent application Ser. No. 10/261,926, filed on Oct. 1, 2002, which is a divisional of U.S. Pat. No. 6,557,640, which was filed as patent application Ser. No. 09/588,946, filed on Jun. 7, 2000, which claims priority from provisional application 60/137,998, filed on Jun. 7, 1999, (62) PCT application US 02/36157, filed on Nov. 12, 2002, which claims priority from U.S. provisional patent application Ser. No. 60/338,996, filed on Nov. 12, 2001, (63) PCT application US 02/36267, filed on Nov. 12, 2002, which claims priority from U.S. provisional patent application Ser. No. 60/339,013, filed on Nov. 12, 2001, (64) PCT application US 03/11765, filed on Apr. 16, 2003, which claims priority from U.S. provisional patent application Ser. No. 60/383,917, filed on May 29, 2002, (65) PCT application US 03/15020, filed on May 12, 2003, which claims priority from U.S. provisional patent application Ser. No. 60/391,703, filed on Jun. 26, 2002, (66) PCT application US 02/39418, filed on Dec. 10, 2002, which claims priority from U.S. provisional patent application Ser. No. 60/346,309, filed on

Jan. 7, 2002, (67) PCT application US 03/06544, filed on Mar. 4, 2003, which claims priority from U.S. provisional patent application Ser. No. 60/372,048, filed on Apr. 12, 2002, (68) U.S. patent application Ser. No. 10/331,718, filed on Dec. 30, 2002, which is a divisional U.S. patent application Ser. No. 09/679,906, filed on Oct. 5, 2000, which claims priority from provisional patent application Ser. No. 60/159,033, filed on Oct. 12, 1999, (69) PCT application US 03/04837, filed on Feb. 29, 2003, which claims priority from U.S. provisional patent application Ser. No. 60/363,829, filed on Mar. 13, 2002, (70) U.S. patent application Ser. No. 10/261,927, filed on Oct. 1, 2002, which is a divisional of U.S. Pat. No. 6,557,640, which was filed as patent application Ser. No. 09/588,946, filed on Jun. 7, 2000, which claims priority from provisional application 60/137,998, filed on Jun. 7, 1999, (71) U.S. patent application Ser. No. 10/262,008, filed on Oct. 1, 2002, which is a divisional of U.S. Pat. No. 6,557,640, which was filed as patent application Ser. No. 09/588,946, filed on Jun. 7, 2000, which claims priority from provisional application 60/137,998, filed on Jun. 7, 1999, (72) U.S. patent application Ser. No. 10/261,925, filed on Oct. 1, 2002, which is a divisional of U.S. Pat. No. 6,557,640, which was filed as patent application Ser. No. 09/588,946, filed on Jun. 7, 2000, which claims priority from provisional application 60/137,998, filed on Jun. 7, 1999, (73) U.S. patent application Ser. No. 10/199,524, filed on Jul. 19, 2002, which is a continuation of U.S. Pat. No. 6,497,289, which was filed as U.S. patent application Ser. No. 09/454,139, filed on Dec. 3, 1999, which claims priority from provisional application 60/111,293, filed on Dec. 7, 1998, (74) PCT application US 03/10144, filed on Mar. 28, 2003, which claims priority from U.S. provisional patent application Ser. No. 60/372,632, filed on Apr. 15, 2002, (75) U.S. provisional patent application Ser. No. 60/412,542, filed on Sep. 20, 2002, (76) PCT application US 03/14153, filed on May 6, 2003, which claims priority from U.S. provisional patent application Ser. No. 60/380,147, filed on May 6, 2002, (77) PCT application US 03/19993, filed on Jun. 24, 2003, which claims priority from U.S. provisional patent application Ser. No. 60/397,284, filed on Jul. 19, 2002, (78) PCT application US 03/13787, filed on May 5, 2003, which claims priority from U.S. provisional patent application Ser. No. 60/387,486, filed on Jun. 10, 2002, (79) PCT application US 03/18530, filed on Jun. 11, 2003, which claims priority from U.S. provisional patent application Ser. No. 60/387,961, filed on Jun. 12, 2002, (80) PCT application US 03/20694, filed on Jul. 1, 2003, which claims priority from U.S. provisional patent application Ser. No. 60/398,061, filed on Jul. 24, 2002, (81) PCT application US 03/20870, filed on Jul. 2, 2003, which claims priority from U.S. provisional patent application Ser. No. 60/399,240, filed on Jul. 29, 2002, (82) U.S. provisional patent application Ser. No. 60/412,487, filed on Sep. 20, 2002, (83) U.S. provisional patent application Ser. No. 60/412,488, filed on Sep. 20, 2002, (84) U.S. patent application Ser. No. 10/280,356, filed on Oct. 25, 2002, which is a continuation of U.S. Pat. No. 6,470,966, which was filed as patent application Ser. No. 09/850,093, filed on May 7, 2001, as a divisional application of U.S. Pat. No. 6,497,289, which was filed as U.S. patent application Ser. No. 09/454,139, filed on Dec. 3, 1999, which claims priority from provisional application 60/111,293, filed on Dec. 7, 1998, (85) U.S. provisional patent application Ser. No. 60/412,177, filed on Sep. 20, 2002, (86) U.S. provisional patent application Ser. No. 60/412,653, filed on Sep. 20, 2002, (87) U.S. provisional patent application Ser. No. 60/405,610, filed on Aug. 23, 2002, (88) U.S. provisional patent application Ser. No.

60/405,394, filed on Aug. 23, 2002, (89) U.S. provisional patent application Ser. No. 60/412,544, filed on Sep. 20, 2002, (90) PCT application US 03/24779, filed on Aug. 8, 2003, which claims priority from U.S. provisional patent application Ser. No. 60/407,442, filed on Aug. 30, 2002, (91) U.S. provisional patent application Ser. No. 60/423,363, filed on Dec. 10, 2002, (92) U.S. provisional patent application Ser. No. 60/412,196, filed on Sep. 20, 2002, (93) U.S. provisional patent application Ser. No. 60/412,187, filed on Sep. 20, 2002, (94) U.S. provisional patent application Ser. No. 60/412,371, filed on Sep. 20, 2002, (95) U.S. patent application Ser. No. 10/382,325, filed on Mar. 5, 2003, which is a continuation of U.S. Pat. No. 6,557,640, which was filed as patent application Ser. No. 09/588,946, filed on Jun. 7, 2000, which claims priority from provisional application 60/137,998, filed on Jun. 7, 1999, (96) U.S. patent application Ser. No. 10/624,842, filed on Jul. 22, 2003, which is a divisional of U.S. patent application Ser. No. 09/502,350, filed on Feb. 10, 2000, which claims priority from provisional application 60/119,611, filed on Feb. 11, 1999, (97) U.S. provisional patent application Ser. No. 60/431,184, filed on Dec. 5, 2002, (98) U.S. provisional patent application Ser. No. 60/448,526, filed on Feb. 18, 2003, (99) U.S. provisional patent application Ser. No. 60/461,539, filed on Apr. 9, 2003, (100) U.S. provisional patent application Ser. No. 60/462,750, filed on Apr. 14, 2003, (101) U.S. provisional patent application Ser. No. 60/436,106, filed on Dec. 23, 2002, (102) U.S. provisional patent application Ser. No. 60/442,942, filed on Jan. 27, 2003, (103) U.S. provisional patent application Ser. No. 60/442,938, filed on Jan. 27, 2003, (104) U.S. provisional patent application Ser. No. 60/418,687, filed on Apr. 18, 2003, (105) U.S. provisional patent application Ser. No. 60/454,896, filed on Mar. 14, 2003, (106) U.S. provisional patent application Ser. No. 60/450,504, filed on Feb. 26, 2003, (107) U.S. provisional patent application Ser. No. 60/451,152, filed on Mar. 9, 2003, (108) U.S. provisional patent application Ser. No. 60/455,124, filed on Mar. 17, 2003, (109) U.S. provisional patent application Ser. No. 60/453,678, filed on Mar. 11, 2003, (110) U.S. patent application Ser. No. 10/421,682, filed on Apr. 23, 2003, which is a continuation of U.S. patent application Ser. No. 09/523,468, filed on Mar. 10, 2000, (now U.S. Pat. No. 6,640,903 which issued Nov. 4, 2003), which claims priority from provisional application 60/124,042, filed on Mar. 11, 1999, (111) U.S. provisional patent application Ser. No. 60/457,965, filed on Mar. 27, 2003, (112) U.S. provisional patent application Ser. No. 60/455,718, filed on Mar. 18, 2003, (113) U.S. Pat. No. 6,550,821, which was filed as patent application Ser. No. 09/811,734, filed on Mar. 19, 2001, (114) U.S. patent application Ser. No. 10/436,467, filed on May 12, 2003, which is a continuation of U.S. Pat. No. 6,604,763, which was filed as application Ser. No. 09/559,122, filed on Apr. 26, 2000, which claims priority from provisional application 60/131,106, filed on Apr. 26, 1999, (115) U.S. provisional patent application Ser. No. 60/459,776, filed on Apr. 2, 2003, (116) U.S. provisional patent application Ser. No. 60/461,094, filed on Apr. 8, 2003, (117) U.S. provisional patent application Ser. No. 60/461,038, filed on Apr. 7, 2003, (118) U.S. provisional patent application Ser. No. 60/463,586, filed on Apr. 17, 2003, (119) U.S. provisional patent application Ser. No. 60/472,240, filed on May 20, 2003, (120) U.S. patent application Ser. No. 10/619,285, filed on Jul. 14, 2003, which is a continuation-in-part of U.S. utility patent application Ser. No. 09/969,922, filed on Oct. 3, 2001, (now U.S. Pat. No. 6,634,431 which issued Oct. 21, 2003), which is a continu-

ation-in-part application of U.S. Pat. No. 6,328,113, which was filed as U.S. patent application Ser. No. 09/440,338, filed on Nov. 15, 1999, which claims priority from provisional application 60/108,558, filed on Nov. 16, 1998, and (121) U.S. utility patent application Ser. No. 10/418,688, which was filed on Apr. 18, 2003, as a division of U.S. utility patent application Ser. No. 09/523,468, filed on Mar. 10, 2000, (now U.S. Pat. No. 6,640,903 which issued Nov. 4, 2003), which claims priority from provisional application 60/124,042, filed on Mar. 11, 1999, the disclosures of which are incorporated herein by reference.

This application is related to the following co-pending applications: (1) PCT patent application serial no. PCT/US2004/06246, filed on Feb. 26, 2004, (2) PCT patent application serial number PCT/US2004/08170, filed on Mar. 15, 2004, (3) PCT patent application serial number PCT/US2004/08171, filed on Mar. 15, 2004, (4) PCT patent application serial number PCT/US2004/08073, filed on Mar. 18, 2004, (5) PCT patent application serial number PCT/US2004/07711, filed on Mar. 11, 2004, (6) PCT patent application serial number PCT/US2004/029025, filed on Mar. 26, 2004, (7) PCT patent application serial number PCT/US2004/010317, filed on Apr. 2, 2004, (8) PCT patent application serial number PCT/US2004/010712, filed on Apr. 6, 2004, (9) PCT patent application serial number PCT/US2004/010762, filed on Apr. 6, 2004, (10) PCT patent application serial number PCT/US2004/011973, filed on Apr. 15, 2004, (11) U.S. provisional patent application Ser. No. 60/495,056, filed on Aug. 14, 2003, (12) U.S. provisional patent application Ser. No. 60/600,679, filed on Aug. 11, 2004, (13) PCT patent application serial number PCT/US2005/027318, filed on Jul. 29, 2005, (14) PCT patent application serial number PCT/US2005/28936, filed on Aug. 12, 2005, (15) PCT patent application serial number PCT/US2005/28669, filed on Aug. 11, 2005, (16) PCT patent application serial number PCT/US2005/28453, filed on Aug. 11, 2005, (17) PCT patent application serial number PCT/US2005/28641, filed on Aug. 11, 2005, (18) PCT patent application serial number PCT/US2005/28819, filed on Aug. 11, 2005, (19) PCT patent application serial number PCT/US2005/28446, filed on Aug. 11, 2005, (20) PCT patent application serial number PCT/US2005/28642, filed on Aug. 11, 2005, (21) PCT patent application serial number PCT/US2005/28451, filed on Aug. 11, 2005, and (22) PCT patent application serial number PCT/US2005/28473, filed on Jul. 29, 2005.

BACKGROUND OF THE INVENTION

This invention relates generally to wellbore casings, and in particular to wellbore casings that are formed using expandable tubing.

Conventionally, when a wellbore is created, a number of casings are installed in the borehole to prevent collapse of the borehole wall and to prevent undesired outflow of drilling fluid into the formation or inflow of fluid from the formation into the borehole. The borehole is drilled in intervals whereby a casing which is to be installed in a lower borehole interval is lowered through a previously installed casing of an upper borehole interval. As a consequence of this procedure the casing of the lower interval is of smaller diameter than the casing of the upper interval. Thus, the casings are in a nested arrangement with casing diameters decreasing in downward direction. Cement annuli are provided between the outer surfaces of the casings and the borehole wall to seal the casings from the borehole wall. As a consequence of this nested arrangement a relatively large

borehole diameter is required at the upper part of the wellbore. Such a large borehole diameter involves increased costs due to heavy casing handling equipment, large drill bits and increased volumes of drilling fluid and drill cuttings. Moreover, increased drilling rig time is involved due to required cement pumping, cement hardening, required equipment changes due to large variations in hole diameters drilled in the course of the well, and the large volume of cuttings drilled and removed.

Conventionally, at the surface end of the wellbore, a wellhead is formed that typically includes a surface casing, a number of production and/or drilling spools, valving, and a Christmas tree. Typically the wellhead further includes a concentric arrangement of casings including a production casing and one or more intermediate casings. The casings are typically supported using load bearing slips positioned above the ground. The conventional design and construction of wellheads is expensive and complex.

The present invention is directed to overcoming one or more of the limitations of the existing procedures for forming wellbores and wellheads.

BRIEF DESCRIPTION OF THE DRAWINGS

FIG. 1 is a fragmentary cross-sectional view illustrating the drilling of a new section of a well borehole.

FIG. 2 is a fragmentary cross-sectional view illustrating the placement of an embodiment of an apparatus for creating a casing within the new section of the well borehole.

FIG. 3 is a fragmentary cross-sectional view illustrating the injection of a first quantity of a fluidic material into the new section of the well borehole.

FIG. 3a is another fragmentary cross-sectional view illustrating the injection of a first quantity of a hardenable fluidic sealing material into the new section of the well borehole.

FIG. 4 is a fragmentary cross-sectional view illustrating the injection of a second quantity of a fluidic material into the new section of the well borehole.

FIG. 5 is a fragmentary cross-sectional view illustrating the drilling out of a portion of the cured hardenable fluidic sealing material from the new section of the well borehole.

FIG. 6 is a cross-sectional view of an embodiment of the overlapping joint between adjacent tubular members.

FIG. 7 is a fragmentary cross-sectional view of an exemplary embodiment of the apparatus for creating a casing within a well borehole.

FIG. 8 is a fragmentary cross-sectional illustration of the placement of an expanded tubular member within another tubular member.

FIG. 9 is a cross-sectional illustration of an exemplary embodiment of an apparatus for forming a casing including a drillable mandrel and shoe.

FIG. 9a is another cross-sectional illustration of the apparatus of FIG. 9.

FIG. 9b is another cross-sectional illustration of the apparatus of FIG. 9.

FIG. 9c is another cross-sectional illustration of the apparatus of FIG. 9.

FIG. 10a is a cross-sectional illustration of a wellbore including a pair of adjacent overlapping casings.

FIG. 10b is a cross-sectional illustration of an apparatus and method for creating a tie-back liner using an expandable tubular member.

FIG. 10c is a cross-sectional illustration of the pumping of a fluidic sealing material into the annular region between the tubular member and the existing casing.

FIG. 10*d* is a cross-sectional illustration of the pressurizing of the interior of the tubular member below the mandrel.

FIG. 10*e* is a cross-sectional illustration of the extrusion of the tubular member off of the mandrel.

FIG. 10*f* is a cross-sectional illustration of the tie-back liner before drilling out the shoe and packer.

FIG. 10*g* is a cross-sectional illustration of the completed tie-back liner created using an expandable tubular member.

FIG. 11*a* is a fragmentary cross-sectional view illustrating the drilling of a new section of a well borehole.

FIG. 11*b* is a fragmentary cross-sectional view illustrating the placement of an embodiment of an apparatus for hanging a tubular liner within the new section of the well borehole.

FIG. 11*c* is a fragmentary cross-sectional view illustrating the injection of a first quantity of a hardenable fluidic sealing material into the new section of the well borehole.

FIG. 11*d* is a fragmentary cross-sectional view illustrating the introduction of a wiper dart into the new section of the well borehole.

FIG. 11*e* is a fragmentary cross-sectional view illustrating the injection of a second quantity of a hardenable fluidic sealing material into the new section of the well borehole.

FIG. 11*f* is a fragmentary cross-sectional view illustrating the completion of the tubular liner.

FIG. 12 is a cross-sectional illustration of an exemplary embodiment of a wellhead system utilizing expandable tubular members.

FIG. 13 is a partial cross-sectional illustration of an exemplary embodiment of the wellhead system of FIG. 12.

FIG. 14*a* is an illustration of the formation of an embodiment of a mono-diameter wellbore casing.

FIG. 14*b* is another illustration of the formation of the mono-diameter wellbore casing.

FIG. 14*c* is another illustration of the formation of the mono-diameter wellbore casing.

FIG. 14*d* is another illustration of the formation of the mono-diameter wellbore casing.

FIG. 14*e* is another illustration of the formation of the mono-diameter wellbore casing.

FIG. 14*f* is another illustration of the formation of the mono-diameter wellbore casing.

FIG. 15 is an illustration of an embodiment of an apparatus for expanding a tubular member.

FIG. 15*a* is another illustration of the apparatus of FIG. 15.

FIG. 15*b* is another illustration of the apparatus of FIG. 15.

FIG. 16 is an illustration of an embodiment of an apparatus for forming a mono-diameter wellbore casing.

FIG. 17 is an illustration of an embodiment of an apparatus for expanding a tubular member.

FIG. 17*a* is another illustration of the apparatus of FIG. 16.

FIG. 17*b* is another illustration of the apparatus of FIG. 16.

FIG. 18 is an illustration of an embodiment of an apparatus for forming a mono-diameter wellbore casing.

FIG. 19 is an illustration of another embodiment of an apparatus for expanding a tubular member.

FIG. 19*a* is another illustration of the apparatus of FIG. 17.

FIG. 19*b* is another illustration of the apparatus of FIG. 17.

FIG. 20 is an illustration of an embodiment of an apparatus for forming a mono-diameter wellbore casing.

FIG. 21 is an illustration of the isolation of subterranean zones using expandable tubulars.

DETAILED DESCRIPTION OF THE ILLUSTRATIVE EMBODIMENTS

An apparatus and method for forming a wellbore casing within a subterranean formation is provided. The apparatus and method permits a wellbore casing to be formed in a subterranean formation by placing a tubular member and a mandrel in a new section of a wellbore, and then extruding the tubular member off of the mandrel by pressurizing an interior portion of the tubular member. The apparatus and method further permits adjacent tubular members in the wellbore to be joined using an overlapping joint that prevents fluid and or gas passage. The apparatus and method further permits a new tubular member to be supported by an existing tubular member by expanding the new tubular member into engagement with the existing tubular member. The apparatus and method further minimizes the reduction in the hole size of the wellbore casing necessitated by the addition of new sections of wellbore casing.

An apparatus and method for forming a tie-back liner using an expandable tubular member is also provided. The apparatus and method permits a tie-back liner to be created by extruding a tubular member off of a mandrel by pressurizing and interior portion of the tubular member. In this manner, a tie-back liner is produced. The apparatus and method further permits adjacent tubular members in the wellbore to be joined using an overlapping joint that prevents fluid and/or gas passage. The apparatus and method further permits a new tubular member to be supported by an existing tubular member by expanding the new tubular member into engagement with the existing tubular member.

An apparatus and method for expanding a tubular member is also provided that includes an expandable tubular member, mandrel and a shoe. In an exemplary embodiment, the interior portions of the apparatus is composed of materials that permit the interior portions to be removed using a conventional drilling apparatus. In this manner, in the event of a malfunction in a downhole region, the apparatus may be easily removed.

An apparatus and method for hanging an expandable tubular liner in a wellbore is also provided. The apparatus and method permit a tubular liner to be attached to an existing section of casing. The apparatus and method further have application to the joining of tubular members in general.

An apparatus and method for forming a wellhead system is also provided. The apparatus and method permit a wellhead to be formed including a number of expandable tubular members positioned in a concentric arrangement. The wellhead preferably includes an outer casing that supports a plurality of concentric casings using contact pressure between the inner casings and the outer casing. The resulting wellhead system eliminates many of the spools conventionally required, reduces the height of the Christmas tree facilitating servicing, lowers the load bearing areas of the wellhead resulting in a more stable system, and eliminates costly and expensive hanger systems.

An apparatus and method for forming a mono-diameter well casing is also provided. The apparatus and method permit the creation of a well casing in a wellbore having a substantially constant internal diameter. In this manner, the operation of an oil or gas well is greatly simplified.

An apparatus and method for expanding tubular members is also provided. The apparatus and method utilize a piston-

cylinder configuration in which a pressurized chamber is used to drive a mandrel to radially expand tubular members. In this manner, higher operating pressures can be utilized. Throughout the radial expansion process, the tubular member is never placed in direct contact with the operating pressures. In this manner, damage to the tubular member is prevented while also permitting controlled radial expansion of the tubular member in a wellbore.

An apparatus and method for forming a mono-diameter wellbore casing is also provided. The apparatus and method utilize a piston-cylinder configuration in which a pressurized chamber is used to drive a mandrel to radially expand tubular members. In this manner, higher operating pressures can be utilized. Throughout the radial expansion process, the tubular member is never placed in direct contact with the operating pressures. In this manner, damage to the tubular member is prevented while also permitting controlled radial expansion of the tubular member in a wellbore.

An apparatus and method for isolating one or more subterranean zones from one or more other subterranean zones is also provided. The apparatus and method permits a producing zone to be isolated from a nonproducing zone using a combination of solid and slotted tubulars. In the production mode, the teachings of the present disclosure may be used in combination with conventional, well known, production completion equipment and methods using a series of packers, solid tubing, perforated tubing, and sliding sleeves, which will be inserted into the disclosed apparatus to permit the commingling and/or isolation of the subterranean zones from each other.

Referring initially to FIGS. 1-5, an embodiment of an apparatus and method for forming a wellbore casing within a subterranean formation will now be described. As illustrated in FIG. 1, a wellbore **100** is positioned in a subterranean formation **105**. The wellbore **100** includes an existing cased section **110** having a tubular casing **115** and an annular outer layer of cement **120**.

In order to extend the wellbore **100** into the subterranean formation **105**, a drill string **125** is used in a well known manner to drill out material from the subterranean formation **105** to form a new section **130**.

As illustrated in FIG. 2, an apparatus **200** for forming a wellbore casing in a subterranean formation is then positioned in the new section **130** of the wellbore **100**. The apparatus **200** preferably includes an expandable mandrel or pig **205**, a tubular member **210**, a shoe **215**, a lower cup seal **220**, an upper cup seal **225**, a fluid passage **230**, a fluid passage **235**, a fluid passage **240**, seals **245**, and a support member **250**.

The expandable mandrel **205** is coupled to and supported by the support member **250**. The expandable mandrel **205** is preferably adapted to controllably expand in a radial direction. The expandable mandrel **205** may comprise any number of conventional commercially available expandable mandrels modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the expandable mandrel **205** comprises a hydraulic expansion tool as disclosed in U.S. Pat. No. 5,348,095, the contents of which are incorporated herein by reference, modified in accordance with the teachings of the present disclosure.

The tubular member **210** is supported by the expandable mandrel **205**. The tubular member **210** is expanded in the radial direction and extruded off of the expandable mandrel **205**. The tubular member **210** may be fabricated from any number of conventional commercially available materials such as, for example, Oilfield Country Tubular Goods (OCTG), 13 chromium steel tubing/casing, or plastic tubing/

casing. In an exemplary embodiment, the tubular member **210** is fabricated from OCTG in order to maximize strength after expansion. The inner and outer diameters of the tubular member **210** may range, for example, from approximately 0.75 to 47 inches and 1.05 to 48 inches, respectively. In an exemplary embodiment, the inner and outer diameters of the tubular member **210** range from about 3 to 15.5 inches and 3.5 to 16 inches, respectively in order to optimally provide minimal telescoping effect in the most commonly drilled wellbore sizes. The tubular member **210** preferably comprises a solid member.

In an exemplary embodiment, the end portion **260** of the tubular member **210** is slotted, perforated, or otherwise modified to catch or slow down the mandrel **205** when it completes the extrusion of tubular member **210**. In an exemplary embodiment, the length of the tubular member **210** is limited to minimize the possibility of buckling. For typical tubular member **210** materials, the length of the tubular member **210** is preferably limited to between about 40 to 20,000 feet in length.

The shoe **215** is coupled to the expandable mandrel **205** and the tubular member **210**. The shoe **215** includes fluid passage **240**. The shoe **215** may comprise any number of conventional commercially available shoes such as, for example, Super Seal II float shoe, Super Seal II Down-Jet float shoe or a guide shoe with a sealing sleeve for a latch down plug modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the shoe **215** comprises an aluminum down-jet guide shoe with a sealing sleeve for a latch-down plug available from Halliburton Energy Services in Dallas, Tex., modified in accordance with the teachings of the present disclosure, in order to optimally guide the tubular member **210** in the wellbore, optimally provide an adequate seal between the interior and exterior diameters of the overlapping joint between the tubular members, and to optimally allow the complete drill out of the shoe and plug after the completion of the cementing and expansion operations.

In an exemplary embodiment, the shoe **215** includes one or more through and side outlet ports in fluidic communication with the fluid passage **240**. In this manner, the shoe **215** optimally injects hardenable fluidic sealing material into the region outside the shoe **215** and tubular member **210**. In an exemplary embodiment, the shoe **215** includes the fluid passage **240** having an inlet geometry that can receive a dart and/or a ball sealing member. In this manner, the fluid passage **240** can be optimally sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage **230**.

The lower cup seal **220** is coupled to and supported by the support member **250**. The lower cup seal **220** prevents foreign materials from entering the interior region of the tubular member **210** adjacent to the expandable mandrel **205**. The lower cup seal **220** may comprise any number of conventional commercially available cup seals such as, for example, TP cups, or Selective Injection Packer (SIP) cups modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the lower cup seal **220** comprises a SIP cup seal, available from Halliburton Energy Services in Dallas, Tex. in order to optimally block foreign material and contain a body of lubricant.

The upper cup seal **225** is coupled to and supported by the support member **250**. The upper cup seal **225** prevents foreign materials from entering the interior region of the tubular member **210**. The upper cup seal **225** may comprise any number of conventional commercially available cup seals such as, for example, TP cups or SIP cups modified in

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accordance with the teachings of the present disclosure. In an exemplary embodiment, the upper cup seal **225** comprises a SIP cup, available from Halliburton Energy Services in Dallas, Tex. in order to optimally block the entry of foreign materials and contain a body of lubricant.

The fluid passage **230** permits fluidic materials to be transported to and from the interior region of the tubular member **210** below the expandable mandrel **205**. The fluid passage **230** is coupled to and positioned within the support member **250** and the expandable mandrel **205**. The fluid passage **230** preferably extends from a position adjacent to the surface to the bottom of the expandable mandrel **205**. The fluid passage **230** is preferably positioned along a centerline of the apparatus **200**.

The fluid passage **230** is preferably selected, in the casing running mode of operation, to transport materials such as drilling mud or formation fluids at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to minimize drag on the tubular member being run and to minimize surge pressures exerted on the wellbore which could cause a loss of wellbore fluids and lead to hole collapse.

The fluid passage **235** permits fluidic materials to be released from the fluid passage **230**. In this manner, during placement of the apparatus **200** within the new section **130** of the wellbore **100**, fluidic materials **255** forced up the fluid passage **230** can be released into the wellbore **100** above the tubular member **210** thereby minimizing surge pressures on the wellbore section **130**. The fluid passage **235** is coupled to and positioned within the support member **250**. The fluid passage is further fluidically coupled to the fluid passage **230**.

The fluid passage **235** preferably includes a control valve for controllably opening and closing the fluid passage **235**. In an exemplary embodiment, the control valve is pressure activated in order to controllably minimize surge pressures. The fluid passage **235** is preferably positioned substantially orthogonal to the centerline of the apparatus **200**.

The fluid passage **235** is preferably selected to convey fluidic materials at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to reduce the drag on the apparatus **200** during insertion into the new section **130** of the wellbore **100** and to minimize surge pressures on the new wellbore section **130**.

The fluid passage **240** permits fluidic materials to be transported to and from the region exterior to the tubular member **210** and shoe **215**. The fluid passage **240** is coupled to and positioned within the shoe **215** in fluidic communication with the interior region of the tubular member **210** below the expandable mandrel **205**. The fluid passage **240** preferably has a cross-sectional shape that permits a plug, or other similar device, to be placed in fluid passage **240** to thereby block further passage of fluidic materials. In this manner, the interior region of the tubular member **210** below the expandable mandrel **205** can be fluidically isolated from the region exterior to the tubular member **210**. This permits the interior region of the tubular member **210** below the expandable mandrel **205** to be pressurized. The fluid passage **240** is preferably positioned substantially along the centerline of the apparatus **200**.

The fluid passage **240** is preferably selected to convey materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to optimally fill the annular region between the tubular member **210** and the new section **130** of the wellbore **100** with fluidic materials. In an exemplary embodiment, the fluid passage **240** includes an inlet geometry that can receive a dart and/or a ball sealing

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member. In this manner, the fluid passage **240** can be sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage **230**.

The seals **245** are coupled to and supported by an end portion **260** of the tubular member **210**. The seals **245** are further positioned on an outer surface **265** of the end portion **260** of the tubular member **210**. The seals **245** permit the overlapping joint between the end portion **270** of the casing **115** and the portion **260** of the tubular member **210** to be fluidically sealed. The seals **245** may comprise any number of conventional commercially available seals such as, for example, lead, rubber, Teflon, or epoxy seals modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the seals **245** are molded from Stratalock epoxy available from Halliburton Energy Services in Dallas, Tex. in order to optimally provide a load bearing interference fit between the end **260** of the tubular member **210** and the end **270** of the existing casing **115**.

In an exemplary embodiment, the seals **245** are selected to optimally provide a sufficient frictional force to support the expanded tubular member **210** from the existing casing **115**. In an exemplary embodiment, the frictional force optimally provided by the seals **245** ranges from about 1,000 to 1,000,000 lbf in order to optimally support the expanded tubular member **210**.

The support member **250** is coupled to the expandable mandrel **205**, tubular member **210**, shoe **215**, and seals **220** and **225**. The support member **250** preferably comprises an annular member having sufficient strength to carry the apparatus **200** into the new section **130** of the wellbore **100**. In an exemplary embodiment, the support member **250** further includes one or more conventional centralizers (not illustrated) to help stabilize the apparatus **200**.

In an exemplary embodiment, a quantity of lubricant **275** is provided in the annular region above the expandable mandrel **205** within the interior of the tubular member **210**. In this manner, the extrusion of the tubular member **210** off of the expandable mandrel **205** is facilitated. The lubricant **275** may comprise any number of conventional commercially available lubricants such as, for example, Lubriplate, chlorine based lubricants, oil based lubricants or Climax 1500 Antisieze (3100). In an exemplary embodiment, the lubricant **275** comprises Climax 1500 Antisieze (3100) available from Climax Lubricants and Equipment Co. in Houston, Tex. in order to optimally provide optimum lubrication to facilitate the expansion process.

In an exemplary embodiment, the support member **250** is thoroughly cleaned prior to assembly to the remaining portions of the apparatus **200**. In this manner, the introduction of foreign material into the apparatus **200** is minimized. This minimizes the possibility of foreign material clogging the various flow passages and valves of the apparatus **200**.

In an exemplary embodiment, before or after positioning the apparatus **200** within the new section **130** of the wellbore **100**, a couple of wellbore volumes are circulated in order to ensure that no foreign materials are located within the wellbore **100** that might clog up the various flow passages and valves of the apparatus **200** and to ensure that no foreign material interferes with the expansion process.

As illustrated in FIG. 3, the fluid passage **235** is then closed and a hardenable fluidic sealing material **305** is then pumped from a surface location into the fluid passage **230**. The material **305** then passes from the fluid passage **230** into the interior region **310** of the tubular member **210** below the expandable mandrel **205**. The material **305** then passes from the interior region **310** into the fluid passage **240**. The material **305** then exits the apparatus **200** and fills the

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annular region 315 between the exterior of the tubular member 210 and the interior wall of the new section 130 of the wellbore 100. Continued pumping of the material 305 causes the material 305 to fill up at least a portion of the annular region 315.

The material 305 is preferably pumped into the annular region 315 at pressures and flow rates ranging, for example, from about 0 to 5000 psi and 0 to 1,500 gallons/min, respectively. The optimum flow rate and operating pressures vary as a function of the casing and wellbore sizes, wellbore section length, available pumping equipment, and fluid properties of the fluidic material being pumped. The optimum flow rate and operating pressure are preferably determined using conventional empirical methods.

The hardenable fluidic sealing material 305 may comprise any number of conventional commercially available hardenable fluidic sealing materials such as, for example, slag mix, cement or epoxy. In an exemplary embodiment, the hardenable fluidic sealing material 305 comprises a blended cement prepared specifically for the particular well section being drilled from Halliburton Energy Services in Dallas, Tex. in order to provide optimal support for tubular member 210 while also maintaining optimum flow characteristics so as to minimize difficulties during the displacement of cement in the annular region 315. The optimum blend of the blended cement is preferably determined using conventional empirical methods.

The annular region 315 preferably is filled with the material 305 in sufficient quantities to ensure that, upon radial expansion of the tubular member 210, the annular region 315 of the new section 130 of the wellbore 100 will be filled with material 305.

In an exemplary embodiment, as illustrated in FIG. 3a, the wall thickness and/or the outer diameter of the tubular member 210 is reduced in the region adjacent to the mandrel 205 in order optimally permit placement of the apparatus 200 in positions in the wellbore with tight clearances. Furthermore, in this manner, the initiation of the radial expansion of the tubular member 210 during the extrusion process is optimally facilitated.

As illustrated in FIG. 4, once the annular region 315 has been adequately filled with material 305, a plug 405, or other similar device, is introduced into the fluid passage 240 thereby fluidically isolating the interior region 310 from the annular region 315. In an exemplary embodiment, a non-hardenable fluidic material 306 is then pumped into the interior region 310 causing the interior region to pressurize. In this manner, the interior of the expanded tubular member 210 will not contain significant amounts of cured material 305. This reduces and simplifies the cost of the entire process. Alternatively, the material 305 may be used during this phase of the process.

Once the interior region 310 becomes sufficiently pressurized, the tubular member 210 is extruded off of the expandable mandrel 205. During the extrusion process, the expandable mandrel 205 may be raised out of the expanded portion of the tubular member 210. In an exemplary embodiment, during the extrusion process, the mandrel 205 is raised at approximately the same rate as the tubular member 210 is expanded in order to keep the tubular member 210 stationary relative to the new wellbore section 130. In an exemplary embodiment, the extrusion process is commenced with the tubular member 210 positioned above the bottom of the new wellbore section 130, keeping the mandrel 205 stationary, and allowing the tubular member 210 to extrude off of the mandrel 205 and fall down the new wellbore section 130 under the force of gravity.

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The plug 405 is preferably placed into the fluid passage 240 by introducing the plug 405 into the fluid passage 230 at a surface location in a conventional manner. The plug 405 preferably acts to fluidically isolate the hardenable fluidic sealing material 305 from the non hardenable fluidic material 306.

The plug 405 may comprise any number of conventional commercially available devices from plugging a fluid passage such as, for example, Multiple Stage Cement (MSC) latch-down plug, Omega latch-down plug or three-wiper latch-down plug modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the plug 405 comprises a MSC latch-down plug available from Halliburton Energy Services in Dallas, Tex.

After placement of the plug 405 in the fluid passage 240, a non hardenable fluidic material 306 is preferably pumped into the interior region 310 at pressures and flow rates ranging, for example, from approximately 400 to 10,000 psi and 30 to 4,000 gallons/min. In this manner, the amount of hardenable fluidic sealing material within the interior 310 of the tubular member 210 is minimized. In an exemplary embodiment, after placement of the plug 405 in the fluid passage 240, the non hardenable material 306 is preferably pumped into the interior region 310 at pressures and flow rates ranging from approximately 500 to 9,000 psi and 40 to 3,000 gallons/min in order to maximize the extrusion speed.

In an exemplary embodiment, the apparatus 200 is adapted to minimize tensile, burst, and friction effects upon the tubular member 210 during the expansion process. These effects will depend upon the geometry of the expansion mandrel 205, the material composition of the tubular member 210 and expansion mandrel 205, the inner diameter of the tubular member 210, the wall thickness of the tubular member 210, the type of lubricant, and the yield strength of the tubular member 210. In general, the thicker the wall thickness, the smaller the inner diameter, and the greater the yield strength of the tubular member 210, then the greater the operating pressures required to extrude the tubular member 210 off of the mandrel 205.

For typical tubular members 210, the extrusion of the tubular member 210 off of the expandable mandrel will begin when the pressure of the interior region 310 reaches, for example, approximately 500 to 9,000 psi.

During the extrusion process, the expandable mandrel 205 may be raised out of the expanded portion of the tubular member 210 at rates ranging, for example, from about 0 to 5 ft/sec. In an exemplary embodiment, during the extrusion process, the expandable mandrel 205 is raised out of the expanded portion of the tubular member 210 at rates ranging from about 0 to 2 ft/sec in order to minimize the time required for the expansion process while also permitting easy control of the expansion process.

When the end portion 260 of the tubular member 210 is extruded off of the expandable mandrel 205, the outer surface 265 of the end portion 260 of the tubular member 210 will preferably contact the interior surface 410 of the end portion 270 of the casing 115 to form an fluid tight overlapping joint. The contact pressure of the overlapping joint may range, for example, from approximately 50 to 20,000 psi. In an exemplary embodiment, the contact pressure of the overlapping joint ranges from approximately 400 to 10,000 psi in order to provide optimum pressure to activate the annular sealing members 245 and optimally provide resistance to axial motion to accommodate typical tensile and compressive loads.

The overlapping joint between the section 410 of the existing casing 115 and the section 265 of the expanded

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tubular member **210** preferably provides a gaseous and fluidic seal. In an exemplary embodiment, the sealing members **245** optimally provide a fluidic and gaseous seal in the overlapping joint.

In an exemplary embodiment, the operating pressure and flow rate of the non hardenable fluidic material **306** is controllably ramped down when the expandable mandrel **205** reaches the end portion **260** of the tubular member **210**. In this manner, the sudden release of pressure caused by the complete extrusion of the tubular member **210** off of the expandable mandrel **205** can be minimized. In an exemplary embodiment, the operating pressure is reduced in a substantially linear fashion from 100% to about 10% during the end of the extrusion process beginning when the mandrel **205** is within about 5 feet from completion of the extrusion process.

Alternatively, or in combination, a shock absorber is provided in the support member **250** in order to absorb the shock caused by the sudden release of pressure. The shock absorber may comprise, for example, any conventional commercially available shock absorber adapted for use in wellbore operations.

Alternatively, or in combination, a mandrel catching structure is provided in the end portion **260** of the tubular member **210** in order to catch or at least decelerate the mandrel **205**.

Once the extrusion process is completed, the expandable mandrel **205** is removed from the wellbore **100**. In an exemplary embodiment, either before or after the removal of the expandable mandrel **205**, the integrity of the fluidic seal of the overlapping joint between the upper portion **260** of the tubular member **210** and the lower portion **270** of the casing **115** is tested using conventional methods.

If the fluidic seal of the overlapping joint between the upper portion **260** of the tubular member **210** and the lower portion **270** of the casing **115** is satisfactory, then any uncured portion of the material **305** within the expanded tubular member **210** is then removed in a conventional manner such as, for example, circulating the uncured material out of the interior of the expanded tubular member **210**. The mandrel **205** is then pulled out of the wellbore section **130** and a drill bit or mill is used in combination with a conventional drilling assembly **505** to drill out any hardened material **305** within the tubular member **210**. The material **305** within the annular region **315** is then allowed to cure.

As illustrated in FIG. 5, preferably any remaining cured material **305** within the interior of the expanded tubular member **210** is then removed in a conventional manner using a conventional drill string **505**. The resulting new section of casing **510** includes the expanded tubular member **210** and an outer annular layer **515** of cured material **305**. The bottom portion of the apparatus **200** comprising the shoe **215** and dart **405** may then be removed by drilling out the shoe **215** and dart **405** using conventional drilling methods.

In an exemplary embodiment, as illustrated in FIG. 6, the upper portion **260** of the tubular member **210** includes one or more sealing members **605** and one or more pressure relief holes **610**. In this manner, the overlapping joint between the lower portion **270** of the casing **115** and the upper portion **260** of the tubular member **210** is pressure-tight and the pressure on the interior and exterior surfaces of the tubular member **210** is equalized during the extrusion process.

In an exemplary embodiment, the sealing members **605** are seated within recesses **615** formed in the outer surface **265** of the upper portion **260** of the tubular member **210**. In

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an exemplary embodiment, the sealing members **605** are bonded or molded onto the outer surface **265** of the upper portion **260** of the tubular member **210**. The pressure relief holes **610** are preferably positioned in the last few feet of the tubular member **210**. The pressure relief holes reduce the operating pressures required to expand the upper portion **260** of the tubular member **210**. This reduction in required operating pressure in turn reduces the velocity of the mandrel **205** upon the completion of the extrusion process. This reduction in velocity in turn minimizes the mechanical shock to the entire apparatus **200** upon the completion of the extrusion process.

Referring now to FIG. 7, an exemplary embodiment of an apparatus **700** for forming a casing within a wellbore preferably includes an expandable mandrel or pig **705**, an expandable mandrel or pig container **710**, a tubular member **715**, a float shoe **720**, a lower cup seal **725**, an upper cup seal **730**, a fluid passage **735**, a fluid passage **740**, a support member **745**, a body of lubricant **750**, an overshot connection **755**, another support member **760**, and a stabilizer **765**.

The expandable mandrel **705** is coupled to and supported by the support member **745**. The expandable mandrel **705** is further coupled to the expandable mandrel container **710**. The expandable mandrel **705** is preferably adapted to controllably expand in a radial direction. The expandable mandrel **705** may comprise any number of conventional commercially available expandable mandrels modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the expandable mandrel **705** comprises a hydraulic expansion tool substantially as disclosed in U.S. Pat. No. 5,348,095, the contents of which are incorporated herein by reference, modified in accordance with the teachings of the present disclosure.

The expandable mandrel container **710** is coupled to and supported by the support member **745**. The expandable mandrel container **710** is further coupled to the expandable mandrel **705**. The expandable mandrel container **710** may be constructed from any number of conventional commercially available materials such as, for example, Oilfield Country Tubular Goods, stainless steel, titanium or high strength steels. In an exemplary embodiment, the expandable mandrel container **710** is fabricated from material having a greater strength than the material from which the tubular member **715** is fabricated. In this manner, the container **710** can be fabricated from a tubular material having a thinner wall thickness than the tubular member **210**. This permits the container **710** to pass through tight clearances thereby facilitating its placement within the wellbore.

In an exemplary embodiment, once the expansion process begins, and the thicker, lower strength material of the tubular member **715** is expanded, the outside diameter of the tubular member **715** is greater than the outside diameter of the container **710**.

The tubular member **715** is coupled to and supported by the expandable mandrel **705**. The tubular member **715** is preferably expanded in the radial direction and extruded off of the expandable mandrel **705** substantially as described above with reference to FIGS. 1-6. The tubular member **715** may be fabricated from any number of materials such as, for example, Oilfield Country Tubular Goods (OCTG), automotive grade steel or plastics. In an exemplary embodiment, the tubular member **715** is fabricated from OCTG.

In an exemplary embodiment, the tubular member **715** has a substantially annular cross-section. In an exemplary embodiment, the tubular member **715** has a substantially circular annular cross-section.

The tubular member **715** preferably includes an upper section **805**, an intermediate section **810**, and a lower section **815**. The upper section **805** of the tubular member **715** preferably is defined by the region beginning in the vicinity of the mandrel container **710** and ending with the top section **820** of the tubular member **715**. The intermediate section **810** of the tubular member **715** is preferably defined by the region beginning in the vicinity of the top of the mandrel container **710** and ending with the region in the vicinity of the mandrel **705**. The lower section of the tubular member **715** is preferably defined by the region beginning in the vicinity of the mandrel **705** and ending at the bottom **825** of the tubular member **715**.

In an exemplary embodiment, the wall thickness of the upper section **805** of the tubular member **715** is greater than the wall thicknesses of the intermediate and lower sections **810** and **815** of the tubular member **715** in order to optimally facilitate the initiation of the extrusion process and optimally permit the apparatus **700** to be positioned in locations in the wellbore having tight clearances.

The outer diameter and wall thickness of the upper section **805** of the tubular member **715** may range, for example, from about 1.05 to 48 inches and $\frac{1}{8}$ to 2 inches, respectively. In an exemplary embodiment, the outer diameter and wall thickness of the upper section **805** of the tubular member **715** range from about 3.5 to 16 inches and $\frac{3}{8}$ to 1.5 inches, respectively.

The outer diameter and wall thickness of the intermediate section **810** of the tubular member **715** may range, for example, from about 2.5 to 50 inches and $\frac{1}{16}$ to 1.5 inches, respectively. In an exemplary embodiment, the outer diameter and wall thickness of the intermediate section **810** of the tubular member **715** range from about 3.5 to 19 inches and $\frac{1}{8}$ to 1.25 inches, respectively.

The outer diameter and wall thickness of the lower section **815** of the tubular member **715** may range, for example, from about 2.5 to 50 inches and $\frac{1}{16}$ to 1.25 inches, respectively. In an exemplary embodiment, the outer diameter and wall thickness of the lower section **810** of the tubular member **715** range from about 3.5 to 19 inches and $\frac{1}{8}$ to 1.25 inches, respectively. In an exemplary embodiment, the wall thickness of the lower section **815** of the tubular member **715** is further increased to increase the strength of the shoe **720** when drillable materials such as, for example, aluminum are used.

The tubular member **715** preferably comprises a solid tubular member. In an exemplary embodiment, the end portion **820** of the tubular member **715** is slotted, perforated, or otherwise modified to catch or slow down the mandrel **705** when it completes the extrusion of tubular member **715**. In an exemplary embodiment, the length of the tubular member **715** is limited to minimize the possibility of buckling. For typical tubular member **715** materials, the length of the tubular member **715** is preferably limited to between about 40 to 20,000 feet in length.

The shoe **720** is coupled to the expandable mandrel **705** and the tubular member **715**. The shoe **720** includes the fluid passage **740**. In an exemplary embodiment, the shoe **720** further includes an inlet passage **830**, and one or more jet ports **835**. In an exemplary embodiment, the cross-sectional shape of the inlet passage **830** is adapted to receive a latch-down dart, or other similar elements, for blocking the inlet passage **830**. The interior of the shoe **720** preferably includes a body of solid material **840** for increasing the strength of the shoe **720**. In an exemplary embodiment, the body of solid material **840** comprises aluminum.

The shoe **720** may comprise any number of conventional commercially available shoes such as, for example, Super Seal II Down-Jet float shoe, or guide shoe with a sealing sleeve for a latch down plug modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the shoe **720** comprises an aluminum down-jet guide shoe with a sealing sleeve for a latch-down plug available from Halliburton Energy Services in Dallas, Tex., modified in accordance with the teachings of the present disclosure, in order to optimize guiding the tubular member **715** in the wellbore, optimize the seal between the tubular member **715** and an existing wellbore casing, and to optimally facilitate the removal of the shoe **720** by drilling it out after completion of the extrusion process.

The lower cup seal **725** is coupled to and supported by the support member **745**. The lower cup seal **725** prevents foreign materials from entering the interior region of the tubular member **715** above the expandable mandrel **705**. The lower cup seal **725** may comprise any number of conventional commercially available cup seals such as, for example, TP cups or Selective Injection Packer (SIP) cups modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the lower cup seal **725** comprises a SIP cup, available from Halliburton Energy Services in Dallas, Tex. in order to optimally provide a debris barrier and hold a body of lubricant.

The upper cup seal **730** is coupled to and supported by the support member **760**. The upper cup seal **730** prevents foreign materials from entering the interior region of the tubular member **715**. The upper cup seal **730** may comprise any number of conventional commercially available cup seals such as, for example, TP cups or Selective Injection Packer (SIP) cup modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the upper cup seal **730** comprises a SIP cup available from Halliburton Energy Services in Dallas, Tex. in order to optimally provide a debris barrier and contain a body of lubricant.

The fluid passage **735** permits fluidic materials to be transported to and from the interior region of the tubular member **715** below the expandable mandrel **705**. The fluid passage **735** is fluidically coupled to the fluid passage **740**. The fluid passage **735** is preferably coupled to and positioned within the support member **760**, the support member **745**, the mandrel container **710**, and the expandable mandrel **705**. The fluid passage **735** preferably extends from a position adjacent to the surface to the bottom of the expandable mandrel **705**. The fluid passage **735** is preferably positioned along a centerline of the apparatus **700**. The fluid passage **735** is preferably selected to transport materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 40 to 3,000 gallons/minute and 500 to 9,000 psi in order to optimally provide sufficient operating pressures to extrude the tubular member **715** off of the expandable mandrel **705**.

As described above with reference to FIGS. 1–6, during placement of the apparatus **700** within a new section of a wellbore, fluidic materials forced up the fluid passage **735** can be released into the wellbore above the tubular member **715**. In an exemplary embodiment, the apparatus **700** further includes a pressure release passage that is coupled to and positioned within the support member **260**. The pressure release passage is further fluidically coupled to the fluid passage **735**. The pressure release passage preferably includes a control valve for controllably opening and closing the fluid passage. In an exemplary embodiment, the control valve is pressure activated in order to controllably minimize

surge pressures. The pressure release passage is preferably positioned substantially orthogonal to the centerline of the apparatus **700**. The pressure release passage is preferably selected to convey materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 0 to 500 gallons/minute and 0 to 1,000 psi in order to reduce the drag on the apparatus **700** during insertion into a new section of a wellbore and to minimize surge pressures on the new wellbore section.

The fluid passage **740** permits fluidic materials to be transported to and from the region exterior to the tubular member **715**. The fluid passage **740** is preferably coupled to and positioned within the shoe **720** in fluidic communication with the interior region of the tubular member **715** below the expandable mandrel **705**. The fluid passage **740** preferably has a cross-sectional shape that permits a plug, or other similar device, to be placed in the inlet **830** of the fluid passage **740** to thereby block further passage of fluidic materials. In this manner, the interior region of the tubular member **715** below the expandable mandrel **705** can be optimally fluidically isolated from the region exterior to the tubular member **715**. This permits the interior region of the tubular member **715** below the expandable mandrel **205** to be pressurized.

The fluid passage **740** is preferably positioned substantially along the centerline of the apparatus **700**. The fluid passage **740** is preferably selected to convey materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to optimally fill an annular region between the tubular member **715** and a new section of a wellbore with fluidic materials. In an exemplary embodiment, the fluid passage **740** includes an inlet passage **830** having a geometry that can receive a dart and/or a ball sealing member. In this manner, the fluid passage **240** can be sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage **230**.

In an exemplary embodiment, the apparatus **700** further includes one or more seals **845** coupled to and supported by the end portion **820** of the tubular member **715**. The seals **845** are further positioned on an outer surface of the end portion **820** of the tubular member **715**. The seals **845** permit the overlapping joint between an end portion of preexisting casing and the end portion **820** of the tubular member **715** to be fluidically sealed. The seals **845** may comprise any number of conventional commercially available seals such as, for example, lead, rubber, Teflon, or epoxy seals modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the seals **845** comprise seals molded from StrataLock epoxy available from Halliburton Energy Services in Dallas, Tex. in order to optimally provide a hydraulic seal and a load bearing interference fit in the overlapping joint between the tubular member **715** and an existing casing with optimal load bearing capacity to support the tubular member **715**.

In an exemplary embodiment, the seals **845** are selected to provide a sufficient frictional force to support the expanded tubular member **715** from the existing casing. In an exemplary embodiment, the frictional force provided by the seals **845** ranges from about 1,000 to 1,000,000 lbf in order to optimally support the expanded tubular member **715**.

The support member **745** is preferably coupled to the expandable mandrel **705** and the overshot connection **755**. The support member **745** preferably comprises an annular member having sufficient strength to carry the apparatus **700** into a new section of a wellbore. The support member **745**

may comprise any number of conventional commercially available support members such as, for example, steel drill pipe, coiled tubing or other high strength tubular modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the support member **745** comprises conventional drill pipe available from various steel mills in the United States.

In an exemplary embodiment, a body of lubricant **750** is provided in the annular region above the expandable mandrel container **710** within the interior of the tubular member **715**. In this manner, the extrusion of the tubular member **715** off of the expandable mandrel **705** is facilitated. The lubricant **705** may comprise any number of conventional commercially available lubricants such as, for example, Lubriplate, chlorine based lubricants, oil based lubricants, or Climax 1500 Antisieze (3100). In an exemplary embodiment, the lubricant **750** comprises Climax 1500 Antisieze (3100) available from Halliburton Energy Services in Houston, Tex. in order to optimally provide lubrication to facilitate the extrusion process.

The overshot connection **755** is coupled to the support member **745** and the support member **760**. The overshot connection **755** preferably permits the support member **745** to be removably coupled to the support member **760**. The overshot connection **755** may comprise any number of conventional commercially available overshot connections such as, for example, Innerstring Sealing Adapter, Innerstring Flat-Face Sealing Adapter or EZ Drill Setting Tool Stinger. In an exemplary embodiment, the overshot connection **755** comprises a Innerstring Adapter with an Upper Guide available from Halliburton Energy Services in Dallas, Tex.

The support member **760** is preferably coupled to the overshot connection **755** and a surface support structure (not illustrated). The support member **760** preferably comprises an annular member having sufficient strength to carry the apparatus **700** into a new section of a wellbore. The support member **760** may comprise any number of conventional commercially available support members such as, for example, steel drill pipe, coiled tubing or other high strength tubulars modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the support member **760** comprises a conventional drill pipe available from steel mills in the United States.

The stabilizer **765** is preferably coupled to the support member **760**. The stabilizer **765** also preferably stabilizes the components of the apparatus **700** within the tubular member **715**. The stabilizer **765** preferably comprises a spherical member having an outside diameter that is about 80 to 99% of the interior diameter of the tubular member **715** in order to optimally minimize buckling of the tubular member **715**. The stabilizer **765** may comprise any number of conventional commercially available stabilizers such as, for example, EZ Drill Star Guides, packer shoes or drag blocks modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the stabilizer **765** comprises a sealing adapter upper guide available from Halliburton Energy Services in Dallas, Tex.

In an exemplary embodiment, the support members **745** and **760** are thoroughly cleaned prior to assembly to the remaining portions of the apparatus **700**. In this manner, the introduction of foreign material into the apparatus **700** is minimized. This minimizes the possibility of foreign material clogging the various flow passages and valves of the apparatus **700**.

In an exemplary embodiment, before or after positioning the apparatus **700** within a new section of a wellbore, a

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couple of wellbore volumes are circulated through the various flow passages of the apparatus 700 in order to ensure that no foreign materials are located within the wellbore that might clog up the various flow passages and valves of the apparatus 700 and to ensure that no foreign material interferes with the expansion mandrel 705 during the expansion process.

In an exemplary embodiment, the apparatus 700 is operated substantially as described above with reference to FIGS. 1–7 to form a new section of casing within a wellbore.

As illustrated in FIG. 8, in an exemplary embodiment, the method and apparatus described herein is used to repair an existing wellbore casing 805 by forming a tubular liner 810 inside of the existing wellbore casing 805. In an exemplary embodiment, an outer annular lining of cement is not provided in the repaired section. In the exemplary embodiment, any number of fluidic materials can be used to expand the tubular liner 810 into intimate contact with the damaged section of the wellbore casing such as, for example, cement, epoxy, slag mix, or drilling mud. In the exemplary embodiment, sealing members 815 are preferably provided at both ends of the tubular member in order to optimally provide a fluidic seal. In an exemplary embodiment, the tubular liner 810 is formed within a horizontally positioned pipeline section, such as those used to transport hydrocarbons or water, with the tubular liner 810 placed in an overlapping relationship with the adjacent pipeline section. In this manner, underground pipelines can be repaired without having to dig out and replace the damaged sections.

In another exemplary embodiment, the method and apparatus described herein is used to directly line a wellbore with a tubular liner 810. In an exemplary embodiment, an outer annular lining of cement is not provided between the tubular liner 810 and the wellbore. In the exemplary embodiment, any number of fluidic materials can be used to expand the tubular liner 810 into intimate contact with the wellbore such as, for example, cement, epoxy, slag mix, or drilling mud.

Referring now to FIGS. 9, 9a, 9b and 9c, an exemplary embodiment of an apparatus 900 for forming a wellbore casing includes an expandable tubular member 902, a support member 904, an expandable mandrel or pig 906, and a shoe 908. In an exemplary embodiment, the design and construction of the mandrel 906 and shoe 908 permits easy removal of those elements by drilling them out. In this manner, the assembly 900 can be easily removed from a wellbore using a conventional drilling apparatus and corresponding drilling methods.

The expandable tubular member 902 preferably includes an upper portion 910, an intermediate portion 912 and a lower portion 914. During operation of the apparatus 900, the tubular member 902 is preferably extruded off of the mandrel 906 by pressurizing an interior region 966 of the tubular member 902. The tubular member 902 preferably has a substantially annular cross-section.

In an exemplary embodiment, an expandable tubular member 915 is coupled to the upper portion 910 of the expandable tubular member 902. During operation of the apparatus 900, the tubular member 915 is preferably extruded off of the mandrel 906 by pressurizing the interior region 966 of the tubular member 902. The tubular member 915 preferably has a substantially annular cross-section. In an exemplary embodiment, the wall thickness of the tubular member 915 is greater than the wall thickness of the tubular member 902.

The tubular member 915 may be fabricated from any number of conventional commercially available materials

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such as, for example, oilfield tubulars, low alloy steels, titanium or stainless steels. In an exemplary embodiment, the tubular member 915 is fabricated from oilfield tubulars in order to optimally provide approximately the same mechanical properties as the tubular member 902. In an exemplary embodiment, the tubular member 915 has a plastic yield point ranging from about 40,000 to 135,000 psi in order to optimally provide approximately the same yield properties as the tubular member 902. The tubular member 915 may comprise a plurality of tubular members coupled end to end.

In an exemplary embodiment, the upper end portion of the tubular member 915 includes one or more sealing members for optimally providing a fluidic and/or gaseous seal with an existing section of wellbore casing.

In an exemplary embodiment, the combined length of the tubular members 902 and 915 are limited to minimize the possibility of buckling. For typical tubular member materials, the combined length of the tubular members 902 and 915 are limited to between about 40 to 20,000 feet in length.

The lower portion 914 of the tubular member 902 is preferably coupled to the shoe 908 by a threaded connection 968. The intermediate portion 912 of the tubular member 902 preferably is placed in intimate sliding contact with the mandrel 906.

The tubular member 902 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield tubulars, low alloy steels, titanium or stainless steels. In an exemplary embodiment, the tubular member 902 is fabricated from oilfield tubulars in order to optimally provide approximately the same mechanical properties as the tubular member 915. In an exemplary embodiment, the tubular member 902 has a plastic yield point ranging from about 40,000 to 135,000 psi in order to optimally provide approximately the same yield properties as the tubular member 915.

The wall thickness of the upper, intermediate, and lower portions, 910, 912 and 914 of the tubular member 902 may range, for example, from about 1/16 to 1.5 inches. In an exemplary embodiment, the wall thickness of the upper, intermediate, and lower portions, 910, 912 and 914 of the tubular member 902 range from about 1/8 to 1.25 in order to optimally provide wall thickness that are about the same as the tubular member 915. In an exemplary embodiment, the wall thickness of the lower portion 914 is less than or equal to the wall thickness of the upper portion 910 in order to optimally provide a geometry that will fit into tight clearances downhole.

The outer diameter of the upper, intermediate, and lower portions, 910, 912 and 914 of the tubular member 902 may range, for example, from about 1.05 to 48 inches. In an exemplary embodiment, the outer diameter of the upper, intermediate, and lower portions, 910, 912 and 914 of the tubular member 902 range from about 3 1/2 to 19 inches in order to optimally provide the ability to expand the most commonly used oilfield tubulars.

The length of the tubular member 902 is preferably limited to between about 2 to 5 feet in order to optimally provide enough length to contain the mandrel 906 and a body of lubricant.

The tubular member 902 may comprise any number of conventional commercially available tubular members modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the tubular member 902 comprises Oilfield Country Tubular Goods available from various U.S. steel mills. The tubular member 915 may comprise any number of conventional commercially avail-

able tubular members modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the tubular member **915** comprises Oilfield Country Tubular Goods available from various U.S. steel mills.

The various elements of the tubular member **902** may be coupled using any number of conventional process such as, for example, threaded connections, welding or machined from one piece. In an exemplary embodiment, the various elements of the tubular member **902** are coupled using welding. The tubular member **902** may comprise a plurality of tubular elements that are coupled end to end. The various elements of the tubular member **915** may be coupled using any number of conventional process such as, for example, threaded connections, welding or machined from one piece. In an exemplary embodiment, the various elements of the tubular member **915** are coupled using welding. The tubular member **915** may comprise a plurality of tubular elements that are coupled end to end. The tubular members **902** and **915** may be coupled using any number of conventional process such as, for example, threaded connections, welding or machined from one piece.

The support member **904** preferably includes an innerstring adapter **916**, a fluid passage **918**, an upper guide **920**, and a coupling **922**. During operation of the apparatus **900**, the support member **904** preferably supports the apparatus **900** during movement of the apparatus **900** within a wellbore. The support member **904** preferably has a substantially annular cross-section.

The support member **904** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield tubulars, low alloy steel, coiled tubing or stainless steel. In an exemplary embodiment, the support member **904** is fabricated from low alloy steel in order to optimally provide high yield strength.

The innerstring adaptor **916** preferably is coupled to and supported by a conventional drill string support from a surface location. The innerstring adaptor **916** may be coupled to a conventional drill string support **971** by a threaded connection **970**.

The fluid passage **918** is preferably used to convey fluids and other materials to and from the apparatus **900**. In an exemplary embodiment, the fluid passage **918** is fluidly coupled to the fluid passage **952**. In an exemplary embodiment, the fluid passage **918** is used to convey hardenable fluidic sealing materials to and from the apparatus **900**. In an exemplary embodiment, the fluid passage **918** may include one or more pressure relief passages (not illustrated) to release fluid pressure during positioning of the apparatus **900** within a wellbore. In an exemplary embodiment, the fluid passage **918** is positioned along a longitudinal centerline of the apparatus **900**. In an exemplary embodiment, the fluid passage **918** is selected to permit the conveyance of hardenable fluidic materials at operating pressures ranging from about 0 to 9,000 psi.

The upper guide **920** is coupled to an upper portion of the support member **904**. The upper guide **920** preferably is adapted to center the support member **904** within the tubular member **915**. The upper guide **920** may comprise any number of conventional guide members modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the upper guide **920** comprises an innerstring adapter available from Halliburton Energy Services in Dallas, Tex. order to optimally guide the apparatus **900** within the tubular member **915**.

The coupling **922** couples the support member **904** to the mandrel **906**. The coupling **922** preferably comprises a conventional threaded connection.

The various elements of the support member **904** may be coupled using any number of conventional processes such as, for example, welding, threaded connections or machined from one piece. In an exemplary embodiment, the various elements of the support member **904** are coupled using threaded connections.

The mandrel **906** preferably includes a retainer **924**, a rubber cup **926**, an expansion cone **928**, a lower cone retainer **930**, a body of cement **932**, a lower guide **934**, an extension sleeve **936**, a spacer **938**, a housing **940**, a sealing sleeve **942**, an upper cone retainer **944**, a lubricator mandrel **946**, a lubricator sleeve **948**, a guide **950**, and a fluid passage **952**.

The retainer **924** is coupled to the lubricator mandrel **946**, lubricator sleeve **948**, and the rubber cup **926**. The retainer **924** couples the rubber cup **926** to the lubricator sleeve **948**. The retainer **924** preferably has a substantially annular cross-section. The retainer **924** may comprise any number of conventional commercially available retainers such as, for example, slotted spring pins or roll pin.

The rubber cup **926** is coupled to the retainer **924**, the lubricator mandrel **946**, and the lubricator sleeve **948**. The rubber cup **926** prevents the entry of foreign materials into the interior region **972** of the tubular member **902** below the rubber cup **926**. The rubber cup **926** may comprise any number of conventional commercially available rubber cups such as, for example, TP cups or Selective Injection Packer (SIP) cup. In an exemplary embodiment, the rubber cup **926** comprises a SIP cup available from Halliburton Energy Services in Dallas, Tex. in order to optimally block foreign materials.

In an exemplary embodiment, a body of lubricant is further provided in the interior region **972** of the tubular member **902** in order to lubricate the interface between the exterior surface of the mandrel **902** and the interior surface of the tubular members **902** and **915**. The lubricant may comprise any number of conventional commercially available lubricants such as, for example, Lubriplate, chlorine based lubricants, oil based lubricants or Climax 1500 Antiseize (3100). In an exemplary embodiment, the lubricant comprises Climax 1500 Antiseize (3100) available from Climax Lubricants and Equipment Co. in Houston, Tex. in order to optimally provide lubrication to facilitate the extrusion process.

The expansion cone **928** is coupled to the lower cone retainer **930**, the body of cement **932**, the lower guide **934**, the extension sleeve **936**, the housing **940**, and the upper cone retainer **944**. In an exemplary embodiment, during operation of the apparatus **900**, the tubular members **902** and **915** are extruded off of the outer surface of the expansion cone **928**. In an exemplary embodiment, axial movement of the expansion cone **928** is prevented by the lower cone retainer **930**, housing **940** and the upper cone retainer **944**. Inner radial movement of the expansion cone **928** is prevented by the body of cement **932**, the housing **940**, and the upper cone retainer **944**.

The expansion cone **928** preferably has a substantially annular cross section. The outside diameter of the expansion cone **928** is preferably tapered to provide a cone shape. The wall thickness of the expansion cone **928** may range, for example, from about 0.125 to 3 inches. In an exemplary embodiment, the wall thickness of the expansion cone **928** ranges from about 0.25 to 0.75 inches in order to optimally provide adequate compressive strength with minimal material. The maximum and minimum outside diameters of the expansion cone **928** may range, for example, from about 1 to 47 inches. In an exemplary embodiment, the maximum

and minimum outside diameters of the expansion cone **928** range from about 3.5 to 19 in order to optimally provide expansion of generally available oilfield tubulars

The expansion cone **928** may be fabricated from any number of conventional commercially available materials such as, for example, ceramic, tool steel, titanium or low alloy steel. In an exemplary embodiment, the expansion cone **928** is fabricated from tool steel in order to optimally provide high strength and abrasion resistance. The surface hardness of the outer surface of the expansion cone **928** may range, for example, from about 50 Rockwell C to 70 Rockwell C. In an exemplary embodiment, the surface hardness of the outer surface of the expansion cone **928** ranges from about 58 Rockwell C to 62 Rockwell C in order to optimally provide high yield strength. In an exemplary embodiment, the expansion cone **928** is heat treated to optimally provide a hard outer surface and a resilient interior body in order to optimally provide abrasion resistance and fracture toughness.

The lower cone retainer **930** is coupled to the expansion cone **928** and the housing **940**. In an exemplary embodiment, axial movement of the expansion cone **928** is prevented by the lower cone retainer **930**. Preferably, the lower cone retainer **930** has a substantially annular cross-section.

The lower cone retainer **930** may be fabricated from any number of conventional commercially available materials such as, for example, ceramic, tool steel, titanium or low alloy steel. In an exemplary embodiment, the lower cone retainer **930** is fabricated from tool steel in order to optimally provide high strength and abrasion resistance. The surface hardness of the outer surface of the lower cone retainer **930** may range, for example, from about 50 Rockwell C to 70 Rockwell C. In an exemplary embodiment, the surface hardness of the outer surface of the lower cone retainer **930** ranges from about 58 Rockwell C to 62 Rockwell C in order to optimally provide high yield strength. In an exemplary embodiment, the lower cone retainer **930** is heat treated to optimally provide a hard outer surface and a resilient interior body in order to optimally provide abrasion resistance and fracture toughness.

In an exemplary embodiment, the lower cone retainer **930** and the expansion cone **928** are formed as an integral one-piece element in order to reduce the number of components and increase the overall strength of the apparatus. The outer surface of the lower cone retainer **930** preferably mates with the inner surfaces of the tubular members **902** and **915**.

The body of cement **932** is positioned within the interior of the mandrel **906**. The body of cement **932** provides an inner bearing structure for the mandrel **906**. The body of cement **932** further may be easily drilled out using a conventional drill device. In this manner, the mandrel **906** may be easily removed using a conventional drilling device.

The body of cement **932** may comprise any number of conventional commercially available cement compounds. Alternatively, aluminum, cast iron or some other drillable metallic, composite, or aggregate material may be substituted for cement. The body of cement **932** preferably has a substantially annular cross-section.

The lower guide **934** is coupled to the extension sleeve **936** and housing **940**. During operation of the apparatus **900**, the lower guide **934** preferably helps guide the movement of the mandrel **906** within the tubular member **902**. The lower guide **934** preferably has a substantially annular cross-section.

The lower guide **934** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield tubulars, low alloy steel or stainless

steel. In an exemplary embodiment, the lower guide **934** is fabricated from low alloy steel in order to optimally provide high yield strength. The outer surface of the lower guide **934** preferably mates with the inner surface of the tubular member **902** to provide a sliding fit.

The extension sleeve **936** is coupled to the lower guide **934** and the housing **940**. During operation of the apparatus **900**, the extension sleeve **936** preferably helps guide the movement of the mandrel **906** within the tubular member **902**. The extension sleeve **936** preferably has a substantially annular cross-section.

The extension sleeve **936** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield tubulars, low alloy steel or stainless steel. In an exemplary embodiment, the extension sleeve **936** is fabricated from low alloy steel in order to optimally provide high yield strength. The outer surface of the extension sleeve **936** preferably mates with the inner surface of the tubular member **902** to provide a sliding fit. In an exemplary embodiment, the extension sleeve **936** and the lower guide **934** are formed as an integral one-piece element in order to minimize the number of components and increase the strength of the apparatus.

The spacer **938** is coupled to the sealing sleeve **942**. The spacer **938** preferably includes the fluid passage **952** and is adapted to mate with the extension tube **960** of the shoe **908**. In this manner, a plug or dart can be conveyed from the surface through the fluid passages **918** and **952** into the fluid passage **962**. Preferably, the spacer **938** has a substantially annular cross-section.

The spacer **938** may be fabricated from any number of conventional commercially available materials such as, for example, steel, aluminum or cast iron. In an exemplary embodiment, the spacer **938** is fabricated from aluminum in order to optimally provide drillability. The end of the spacer **938** preferably mates with the end of the extension tube **960**. In an exemplary embodiment, the spacer **938** and the sealing sleeve **942** are formed as an integral one-piece element in order to reduce the number of components and increase the strength of the apparatus.

The housing **940** is coupled to the lower guide **934**, extension sleeve **936**, expansion cone **928**, body of cement **932**, and lower cone retainer **930**. During operation of the apparatus **900**, the housing **940** preferably prevents inner radial motion of the expansion cone **928**. Preferably, the housing **940** has a substantially annular cross-section.

The housing **940** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield tubulars, low alloy steel or stainless steel. In an exemplary embodiment, the housing **940** is fabricated from low alloy steel in order to optimally provide high yield strength. In an exemplary embodiment, the lower guide **934**, extension sleeve **936** and housing **940** are formed as an integral one-piece element in order to minimize the number of components and increase the strength of the apparatus.

In an exemplary embodiment, the interior surface of the housing **940** includes one or more protrusions to facilitate the connection between the housing **940** and the body of cement **932**.

The sealing sleeve **942** is coupled to the support member **904**, the body of cement **932**, the spacer **938**, and the upper cone retainer **944**. During operation of the apparatus, the sealing sleeve **942** preferably provides support for the mandrel **906**. The sealing sleeve **942** is preferably coupled to the support member **904** using the coupling **922**. Preferably, the sealing sleeve **942** has a substantially annular cross-section.

The sealing sleeve 942 may be fabricated from any number of conventional commercially available materials such as, for example, steel, aluminum or cast iron. In an exemplary embodiment, the sealing sleeve 942 is fabricated from aluminum in order to optimally provide drillability of the sealing sleeve 942.

In an exemplary embodiment, the outer surface of the sealing sleeve 942 includes one or more protrusions to facilitate the connection between the sealing sleeve 942 and the body of cement 932.

In an exemplary embodiment, the spacer 938 and the sealing sleeve 942 are integrally formed as a one-piece element in order to minimize the number of components.

The upper cone retainer 944 is coupled to the expansion cone 928, the sealing sleeve 942, and the body of cement 932. During operation of the apparatus 900, the upper cone retainer 944 preferably prevents axial motion of the expansion cone 928. Preferably, the upper cone retainer 944 has a substantially annular cross-section.

The upper cone retainer 944 may be fabricated from any number of conventional commercially available materials such as, for example, steel, aluminum or cast iron. In an exemplary embodiment, the upper cone retainer 944 is fabricated from aluminum in order to optimally provide drillability of the upper cone retainer 944.

In an exemplary embodiment, the upper cone retainer 944 has a cross-sectional shape designed to provide increased rigidity. In an exemplary embodiment, the upper cone retainer 944 has a cross-sectional shape that is substantially I-shaped to provide increased rigidity and minimize the amount of material that would have to be drilled out.

The lubricator mandrel 946 is coupled to the retainer 924, the rubber cup 926, the upper cone retainer 944, the lubricator sleeve 948, and the guide 950. During operation of the apparatus 900, the lubricator mandrel 946 preferably contains the body of lubricant in the annular region 972 for lubricating the interface between the mandrel 906 and the tubular member 902. Preferably, the lubricator mandrel 946 has a substantially annular cross-section.

The lubricator mandrel 946 may be fabricated from any number of conventional commercially available materials such as, for example, steel, aluminum or cast iron. In an exemplary embodiment, the lubricator mandrel 946 is fabricated from aluminum in order to optimally provide drillability of the lubricator mandrel 946.

The lubricator sleeve 948 is coupled to the lubricator mandrel 946, the retainer 924, the rubber cup 926, the upper cone retainer 944, the lubricator sleeve 948, and the guide 950. During operation of the apparatus 900, the lubricator sleeve 948 preferably supports the rubber cup 926. Preferably, the lubricator sleeve 948 has a substantially annular cross-section.

The lubricator sleeve 948 may be fabricated from any number of conventional commercially available materials such as, for example, steel, aluminum or cast iron. In an exemplary embodiment, the lubricator sleeve 948 is fabricated from aluminum in order to optimally provide drillability of the lubricator sleeve 948.

As illustrated in FIG. 9c, the lubricator sleeve 948 is supported by the lubricator mandrel 946. The lubricator sleeve 948 in turn supports the rubber cup 926. The retainer 924 couples the rubber cup 926 to the lubricator sleeve 948. In an exemplary embodiment, seals 949a and 949b are provided between the lubricator mandrel 946, lubricator sleeve 948, and rubber cup 926 in order to optimally seal off the interior region 972 of the tubular member 902.

The guide 950 is coupled to the lubricator mandrel 946, the retainer 924, and the lubricator sleeve 948. During operation of the apparatus 900, the guide 950 preferably guides the apparatus on the support member 904. Preferably, the guide 950 has a substantially annular cross-section.

The guide 950 may be fabricated from any number of conventional commercially available materials such as, for example, steel, aluminum or cast iron. In an exemplary embodiment, the guide 950 is fabricated from aluminum in order to optimally provide drillability of the guide 950.

The fluid passage 952 is coupled to the mandrel 906. During operation of the apparatus, the fluid passage 952 preferably conveys hardenable fluidic materials. In an exemplary embodiment, the fluid passage 952 is positioned about the centerline of the apparatus 900. In an exemplary embodiment, the fluid passage 952 is adapted to convey hardenable fluidic materials at pressures and flow rate ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/min in order to optimally provide pressures and flow rates to displace and circulate fluids during the installation of the apparatus 900.

The various elements of the mandrel 906 may be coupled using any number of conventional process such as, for example, threaded connections, welded connections or cementing. In an exemplary embodiment, the various elements of the mandrel 906 are coupled using threaded connections and cementing.

The shoe 908 preferably includes a housing 954, a body of cement 956, a sealing sleeve 958, an extension tube 960, a fluid passage 962, and one or more outlet jets 964.

The housing 954 is coupled to the body of cement 956 and the lower portion 914 of the tubular member 902. During operation of the apparatus 900, the housing 954 preferably couples the lower portion of the tubular member 902 to the shoe 908 to facilitate the extrusion and positioning of the tubular member 902. Preferably, the housing 954 has a substantially annular cross-section.

The housing 954 may be fabricated from any number of conventional commercially available materials such as, for example, steel or aluminum. In an exemplary embodiment, the housing 954 is fabricated from aluminum in order to optimally provide drillability of the housing 954.

In an exemplary embodiment, the interior surface of the housing 954 includes one or more protrusions to facilitate the connection between the body of cement 956 and the housing 954.

The body of cement 956 is coupled to the housing 954, and the sealing sleeve 958. In an exemplary embodiment, the composition of the body of cement 956 is selected to permit the body of cement to be easily drilled out using conventional drilling machines and processes.

The composition of the body of cement 956 may include any number of conventional cement compositions. In an alternative embodiment, a drillable material such as, for example, aluminum or iron may be substituted for the body of cement 956.

The sealing sleeve 958 is coupled to the body of cement 956, the extension tube 960, the fluid passage 962, and one or more outlet jets 964. During operation of the apparatus 900, the sealing sleeve 958 preferably is adapted to convey a hardenable fluidic material from the fluid passage 952 into the fluid passage 962 and then into the outlet jets 964 in order to inject the hardenable fluidic material into an annular region external to the tubular member 902. In an exemplary embodiment, during operation of the apparatus 900, the sealing sleeve 958 further includes an inlet geometry that permits a conventional plug or dart 974 to become lodged in the inlet of the sealing sleeve 958. In this manner, the fluid

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passage 962 may be blocked thereby fluidically isolating the interior region 966 of the tubular member 902.

In an exemplary embodiment, the sealing sleeve 958 has a substantially annular cross-section. The sealing sleeve 958 may be fabricated from any number of conventional commercially available materials such as, for example, steel, aluminum or cast iron. In an exemplary embodiment, the sealing sleeve 958 is fabricated from aluminum in order to optimally provide drillability of the sealing sleeve 958.

The extension tube 960 is coupled to the sealing sleeve 958, the fluid passage 962, and one or more outlet jets 964. During operation of the apparatus 900, the extension tube 960 preferably is adapted to convey a hardenable fluidic material from the fluid passage 952 into the fluid passage 962 and then into the outlet jets 964 in order to inject the hardenable fluidic material into an annular region external to the tubular member 902. In an exemplary embodiment, during operation of the apparatus 900, the sealing sleeve 960 further includes an inlet geometry that permits a conventional plug or dart 974 to become lodged in the inlet of the sealing sleeve 958. In this manner, the fluid passage 962 is blocked thereby fluidically isolating the interior region 966 of the tubular member 902. In an exemplary embodiment, one end of the extension tube 960 mates with one end of the spacer 938 in order to optimally facilitate the transfer of material between the two.

In an exemplary embodiment, the extension tube 960 has a substantially annular cross-section. The extension tube 960 may be fabricated from any number of conventional commercially available materials such as, for example, steel, aluminum or cast iron. In an exemplary embodiment, the extension tube 960 is fabricated from aluminum in order to optimally provide drillability of the extension tube 960.

The fluid passage 962 is coupled to the sealing sleeve 958, the extension tube 960, and one or more outlet jets 964. During operation of the apparatus 900, the fluid passage 962 is preferably conveys hardenable fluidic materials. In an exemplary embodiment, the fluid passage 962 is positioned about the centerline of the apparatus 900. In an exemplary embodiment, the fluid passage 962 is adapted to convey hardenable fluidic materials at pressures and flow rate ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/min in order to optimally provide fluids at operationally efficient rates.

The outlet jets 964 are coupled to the sealing sleeve 958, the extension tube 960, and the fluid passage 962. During operation of the apparatus 900, the outlet jets 964 preferably convey hardenable fluidic material from the fluid passage 962 to the region exterior of the apparatus 900. In an exemplary embodiment, the shoe 908 includes a plurality of outlet jets 964.

In an exemplary embodiment, the outlet jets 964 comprise passages drilled in the housing 954 and the body of cement 956 in order to simplify the construction of the apparatus 900.

The various elements of the shoe 908 may be coupled using any number of conventional process such as, for example, threaded connections, cement or machined from one piece of material. In an exemplary embodiment, the various elements of the shoe 908 are coupled using cement.

In an exemplary embodiment, the assembly 900 is operated substantially as described above with reference to FIGS. 1-8 to create a new section of casing in a wellbore or to repair a wellbore casing or pipeline.

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In particular, in order to extend a wellbore into a subterranean formation, a drill string is used in a well known manner to drill out material from the subterranean formation to form a new section.

The apparatus 900 for forming a wellbore casing in a subterranean formation is then positioned in the new section of the wellbore. In an exemplary embodiment, the apparatus 900 includes the tubular member 915. In an exemplary embodiment, a hardenable fluidic sealing hardenable fluidic sealing material is then pumped from a surface location into the fluid passage 918. The hardenable fluidic sealing material then passes from the fluid passage 918 into the interior region 966 of the tubular member 902 below the mandrel 906. The hardenable fluidic sealing material then passes from the interior region 966 into the fluid passage 962. The hardenable fluidic sealing material then exits the apparatus 900 via the outlet jets 964 and fills an annular region between the exterior of the tubular member 902 and the interior wall of the new section of the wellbore. Continued pumping of the hardenable fluidic sealing material causes the material to fill up at least a portion of the annular region.

The hardenable fluidic sealing material is preferably pumped into the annular region at pressures and flow rates ranging, for example, from about 0 to 5,000 psi and 0 to 1,500 gallons/min, respectively. In an exemplary embodiment, the hardenable fluidic sealing material is pumped into the annular region at pressures and flow rates that are designed for the specific wellbore section in order to optimize the displacement of the hardenable fluidic sealing material while not creating high enough circulating pressures such that circulation might be lost and that could cause the wellbore to collapse. The optimum pressures and flow rates are preferably determined using conventional empirical methods.

The hardenable fluidic sealing material may comprise any number of conventional commercially available hardenable fluidic sealing materials such as, for example, slag mix, cement or epoxy. In an exemplary embodiment, the hardenable fluidic sealing material comprises blended cements designed specifically for the well section being lined available from Halliburton Energy Services in Dallas, Tex. in order to optimally provide support for the new tubular member while also maintaining optimal flow characteristics so as to minimize operational difficulties during the displacement of the cement in the annular region. The optimum composition of the blended cements is preferably determined using conventional empirical methods.

The annular region preferably is filled with the hardenable fluidic sealing material in sufficient quantities to ensure that, upon radial expansion of the tubular member 902, the annular region of the new section of the wellbore will be filled with hardenable material.

Once the annular region has been adequately filled with hardenable fluidic sealing material, a plug or dart 974, or other similar device, preferably is introduced into the fluid passage 962 thereby fluidically isolating the interior region 966 of the tubular member 902 from the external annular region. In an exemplary embodiment, a non hardenable fluidic material is then pumped into the interior region 966 causing the interior region 966 to pressurize. In an exemplary embodiment, the plug or dart 974, or other similar device, preferably is introduced into the fluid passage 962 by introducing the plug or dart 974, or other similar device into the non hardenable fluidic material. In this manner, the amount of cured material within the interior of the tubular members 902 and 915 is minimized.

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Once the interior region 966 becomes sufficiently pressurized, the tubular members 902 and 915 are extruded off of the mandrel 906. The mandrel 906 may be fixed or it may be expandable. During the extrusion process, the mandrel 906 is raised out of the expanded portions of the tubular members 902 and 915 using the support member 904. During this extrusion process, the shoe 908 is preferably substantially stationary.

The plug or dart 974 is preferably placed into the fluid passage 962 by introducing the plug or dart 974 into the fluid passage 918 at a surface location in a conventional manner. The plug or dart 974 may comprise any number of conventional commercially available devices for plugging a fluid passage such as, for example, Multiple Stage Cementer (MSC) latch-down plug, Omega latch-down plug or three-wiper latch down plug modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the plug or dart 974 comprises a MSC latch-down plug available from Halliburton Energy Services in Dallas, Tex.

After placement of the plug or dart 974 in the fluid passage 962, the non hardenable fluidic material is preferably pumped into the interior region 966 at pressures and flow rates ranging from approximately 500 to 9,000 psi and 40 to 3,000 gallons/min in order to optimally extrude the tubular members 902 and 915 off of the mandrel 906.

For typical tubular members 902 and 915, the extrusion of the tubular members 902 and 915 off of the expandable mandrel will begin when the pressure of the interior region 966 reaches approximately 500 to 9,000 psi. In an exemplary embodiment, the extrusion of the tubular members 902 and 915 off of the mandrel 906 begins when the pressure of the interior region 966 reaches approximately 1,200 to 8,500 psi with a flow rate of about 40 to 1250 gallons/minute.

During the extrusion process, the mandrel 906 may be raised out of the expanded portions of the tubular members 902 and 915 at rates ranging, for example, from about 0 to 5 ft/sec. In an exemplary embodiment, during the extrusion process, the mandrel 906 is raised out of the expanded portions of the tubular members 902 and 915 at rates ranging from about 0 to 2 ft/sec in order to optimally provide pulling speed, fast enough to permit efficient operation and permit full expansion of the tubular members 902 and 915 prior to curing of the hardenable fluidic sealing material; but not so fast that timely adjustment of operating parameters during operation is prevented.

When the upper end portion of the tubular member 915 is extruded off of the mandrel 906, the outer surface of the upper end portion of the tubular member 915 will preferably contact the interior surface of the lower end portion of the existing casing to form an fluid tight overlapping joint. The contact pressure of the overlapping joint may range, for example, from approximately 50 to 20,000 psi. In an exemplary embodiment, the contact pressure of the overlapping joint between the upper end of the tubular member 915 and the existing section of wellbore casing ranges from approximately 400 to 10,000 psi in order to optimally provide contact pressure to activate the sealing members and provide optimal resistance such that the tubular member 915 and existing wellbore casing will carry typical tensile and compressive loads.

In an exemplary embodiment, the operating pressure and flow rate of the non hardenable fluidic material will be controllably ramped down when the mandrel 906 reaches the upper end portion of the tubular member 915. In this manner, the sudden release of pressure caused by the complete extrusion of the tubular member 915 off of the expand-

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able mandrel 906 can be minimized. In an exemplary embodiment, the operating pressure is reduced in a substantially linear fashion from 100% to about 10% during the end of the extrusion process beginning when the mandrel 906 has completed approximately all but about the last 5 feet of the extrusion process.

In an exemplary embodiment, the operating pressure and/or flow rate of the hardenable fluidic sealing material and/or the non hardenable fluidic material are controlled during all phases of the operation of the apparatus 900 to minimize shock.

Alternatively, or in combination, a shock absorber is provided in the support member 904 in order to absorb the shock caused by the sudden release of pressure.

Alternatively, or in combination, a mandrel catching structure is provided above the support member 904 in order to catch or at least decelerate the mandrel 906.

Once the extrusion process is completed, the mandrel 906 is removed from the wellbore. In an exemplary embodiment, either before or after the removal of the mandrel 906, the integrity of the fluidic seal of the overlapping joint between the upper portion of the tubular member 915 and the lower portion of the existing casing is tested using conventional methods. If the fluidic seal of the overlapping joint between the upper portion of the tubular member 915 and the lower portion of the existing casing is satisfactory, then the uncured portion of any of the hardenable fluidic sealing material within the expanded tubular member 915 is then removed in a conventional manner. The hardenable fluidic sealing material within the annular region between the expanded tubular member 915 and the existing casing and new section of wellbore is then allowed to cure.

Preferably any remaining cured hardenable fluidic sealing material within the interior of the expanded tubular members 902 and 915 is then removed in a conventional manner using a conventional drill string. The resulting new section of casing preferably includes the expanded tubular members 902 and 915 and an outer annular layer of cured hardenable fluidic sealing material. The bottom portion of the apparatus 900 comprising the shoe 908 may then be removed by drilling out the shoe 908 using conventional drilling methods.

In an alternative embodiment, during the extrusion process, it may be necessary to remove the entire apparatus 900 from the interior of the wellbore due to a malfunction. In this circumstance, a conventional drill string is used to drill out the interior sections of the apparatus 900 in order to facilitate the removal of the remaining sections. In an exemplary embodiment, the interior elements of the apparatus 900 are fabricated from materials such as, for example, cement and aluminum, that permit a conventional drill string to be employed to drill out the interior components.

In particular, in an exemplary embodiment, the composition of the interior sections of the mandrel 906 and shoe 908, including one or more of the body of cement 932, the spacer 938, the sealing sleeve 942, the upper cone retainer 944, the lubricator mandrel 946, the lubricator sleeve 948, the guide 950, the housing 954, the body of cement 956, the sealing sleeve 958, and the extension tube 960, are selected to permit at least some of these components to be drilled out using conventional drilling methods and apparatus. In this manner, in the event of a malfunction downhole, the apparatus 900 may be easily removed from the wellbore.

Referring now to FIGS. 10a, 10b, 10c, 10d, 10e, 10f, and 10g a method and apparatus for creating a tie-back liner in a wellbore will now be described. As illustrated in FIG. 10a,

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a wellbore **1000** positioned in a subterranean formation **1002** includes a first casing **1004** and a second casing **1006**.

The first casing **1004** preferably includes a tubular liner **1008** and a cement annulus **1010**. The second casing **1006** preferably includes a tubular liner **1012** and a cement annulus **1014**. In an exemplary embodiment, the second casing **1006** is formed by expanding a tubular member substantially as described above with reference to FIGS. 1-9c or below with reference to FIGS. 11a-11f.

In an exemplary embodiment, an upper portion of the tubular liner **1012** overlaps with a lower portion of the tubular liner **1008**. In an exemplary embodiment, an outer surface of the upper portion of the tubular liner **1012** includes one or more sealing members **1016** for providing a fluidic seal between the tubular liners **1008** and **1012**.

Referring to FIG. 10b, in order to create a tie-back liner that extends from the overlap between the first and second casings, **1004** and **1006**, an apparatus **1100** is preferably provided that includes an expandable mandrel or pig **1105**, a tubular member **1110**, a shoe **1115**, one or more cup seals **1120**, a fluid passage **1130**, a fluid passage **1135**, one or more fluid passages **1140**, seals **1145**, and a support member **1150**.

The expandable mandrel or pig **1105** is coupled to and supported by the support member **1150**. The expandable mandrel **1105** is preferably adapted to controllably expand in a radial direction. The expandable mandrel **1105** may comprise any number of conventional commercially available expandable mandrels modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the expandable mandrel **1105** comprises a hydraulic expansion tool substantially as disclosed in U.S. Pat. No. 5,348,095, the disclosure of which is incorporated herein by reference, modified in accordance with the teachings of the present disclosure.

The tubular member **1110** is coupled to and supported by the expandable mandrel **1105**. The tubular member **1105** is expanded in the radial direction and extruded off of the expandable mandrel **1105**. The tubular member **1110** may be fabricated from any number of materials such as, for example, Oilfield Country Tubular Goods, 13 chromium tubing or plastic piping. In an exemplary embodiment, the tubular member **1110** is fabricated from Oilfield Country Tubular Goods.

The inner and outer diameters of the tubular member **1110** may range, for example, from approximately 0.75 to 47 inches and 1.05 to 48 inches, respectively. In an exemplary embodiment, the inner and outer diameters of the tubular member **1110** range from about 3 to 15.5 inches and 3.5 to 16 inches, respectively in order to optimally provide coverage for typical oilfield casing sizes. The tubular member **1110** preferably comprises a solid member.

In an exemplary embodiment, the upper end portion of the tubular member **1110** is slotted, perforated, or otherwise modified to catch or slow down the mandrel **1105** when it completes the extrusion of tubular member **1110**. In an exemplary embodiment, the length of the tubular member **1110** is limited to minimize the possibility of buckling. For typical tubular member **1110** materials, the length of the tubular member **1110** is preferably limited to between about 40 to 20,000 feet in length.

The shoe **1115** is coupled to the expandable mandrel **1105** and the tubular member **1110**. The shoe **1115** includes the fluid passage **1135**. The shoe **1115** may comprise any number of conventional commercially available shoes such as, for example, Super Seal II float shoe, Super Seal II Down-Jet float shoe or a guide shoe with a sealing sleeve for a latch down plug modified in accordance with the teachings

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of the present disclosure. In an exemplary embodiment, the shoe **1115** comprises an aluminum down-jet guide shoe with a sealing sleeve for a latch-down plug with side ports radiating off of the exit flow port available from Halliburton Energy Services in Dallas, Tex., modified in accordance with the teachings of the present disclosure, in order to optimally guide the tubular member **1100** to the overlap between the tubular member **1100** and the casing **1012**, optimally fluidically isolate the interior of the tubular member **1100** after the latch down plug has seated, and optimally permit drilling out of the shoe **1115** after completion of the expansion and cementing operations.

In an exemplary embodiment, the shoe **1115** includes one or more side outlet ports **1140** in fluidic communication with the fluid passage **1135**. In this manner, the shoe **1115** injects hardenable fluidic sealing material into the region outside the shoe **1115** and tubular member **1110**. In an exemplary embodiment, the shoe **1115** includes one or more of the fluid passages **1140** each having an inlet geometry that can receive a dart and/or a ball sealing member. In this manner, the fluid passages **1140** can be sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage **1130**.

The cup seal **1120** is coupled to and supported by the support member **1150**. The cup seal **1120** prevents foreign materials from entering the interior region of the tubular member **1110** adjacent to the expandable mandrel **1105**. The cup seal **1120** may comprise any number of conventional commercially available cup seals such as, for example, TP cups or Selective Injection Packer (SIP) cups modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the cup seal **1120** comprises a SIP cup, available from Halliburton Energy Services in Dallas, Tex. in order to optimally provide a barrier to debris and contain a body of lubricant.

The fluid passage **1130** permits fluidic materials to be transported to and from the interior region of the tubular member **1110** below the expandable mandrel **1105**. The fluid passage **1130** is coupled to and positioned within the support member **1150** and the expandable mandrel **1105**. The fluid passage **1130** preferably extends from a position adjacent to the surface to the bottom of the expandable mandrel **1105**. The fluid passage **1130** is preferably positioned along a centerline of the apparatus **1100**. The fluid passage **1130** is preferably selected to transport materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to optimally provide sufficient operating pressures to circulate fluids at operationally efficient rates.

The fluid passage **1135** permits fluidic materials to be transmitted from fluid passage **1130** to the interior of the tubular member **1110** below the mandrel **1105**.

The fluid passages **1140** permits fluidic materials to be transported to and from the region exterior to the tubular member **1110** and shoe **1115**. The fluid passages **1140** are coupled to and positioned within the shoe **1115** in fluidic communication with the interior region of the tubular member **1110** below the expandable mandrel **1105**. The fluid passages **1140** preferably have a cross-sectional shape that permits a plug, or other similar device, to be placed in the fluid passages **1140** to thereby block further passage of fluidic materials. In this manner, the interior region of the tubular member **1110** below the expandable mandrel **1105** can be fluidically isolated from the region exterior to the tubular member **1110**. This permits the interior region of the tubular member **1110** below the expandable mandrel **1105** to be pressurized.

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The fluid passages **1140** are preferably positioned along the periphery of the shoe **1115**. The fluid passages **1140** are preferably selected to convey materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to optimally fill the annular region between the tubular member **1110** and the tubular liner **1008** with fluidic materials. In an exemplary embodiment, the fluid passages **1140** include an inlet geometry that can receive a dart and/or a ball sealing member. In this manner, the fluid passages **1140** can be sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage **1130**. In an exemplary embodiment, the apparatus **1100** includes a plurality of fluid passage **1140**.

In an alternative embodiment, the base of the shoe **1115** includes a single inlet passage coupled to the fluid passages **1140** that is adapted to receive a plug, or other similar device, to permit the interior region of the tubular member **1110** to be fluidically isolated from the exterior of the tubular member **1110**.

The seals **1145** are coupled to and supported by a lower end portion of the tubular member **1110**. The seals **1145** are further positioned on an outer surface of the lower end portion of the tubular member **1110**. The seals **1145** permit the overlapping joint between the upper end portion of the casing **1012** and the lower end portion of the tubular member **1110** to be fluidically sealed.

The seals **1145** may comprise any number of conventional commercially available seals such as, for example, lead, rubber, Teflon or epoxy seals modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the seals **1145** comprise seals molded from Stratalock epoxy available from Halliburton Energy Services in Dallas, Tex. in order to optimally provide a hydraulic seal in the overlapping joint and optimally provide load carrying capacity to withstand the range of typical tensile and compressive loads.

In an exemplary embodiment, the seals **1145** are selected to optimally provide a sufficient frictional force to support the expanded tubular member **1110** from the tubular liner **1008**. In an exemplary embodiment, the frictional force provided by the seals **1145** ranges from about 1,000 to 1,000,000 lbf in tension and compression in order to optimally support the expanded tubular member **1110**.

The support member **1150** is coupled to the expandable mandrel **1105**, tubular member **1110**, shoe **1115**, and seal **1120**. The support member **1150** preferably comprises an annular member having sufficient strength to carry the apparatus **1100** into the wellbore **1000**. In an exemplary embodiment, the support member **1150** further includes one or more conventional centralizers (not illustrated) to help stabilize the tubular member **1110**.

In an exemplary embodiment, a quantity of lubricant **1150** is provided in the annular region above the expandable mandrel **1105** within the interior of the tubular member **1110**. In this manner, the extrusion of the tubular member **1110** off of the expandable mandrel **1105** is facilitated. The lubricant **1150** may comprise any number of conventional commercially available lubricants such as, for example, Lubriplate, chlorine based lubricants or Climax 1500 Antiseize (3100). In an exemplary embodiment, the lubricant **1150** comprises Climax 1500 Antiseize (3100) available from Climax Lubricants and Equipment Co. in Houston, Tex. in order to optimally provide lubrication for the extrusion process.

In an exemplary embodiment, the support member **1150** is thoroughly cleaned prior to assembly to the remaining

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portions of the apparatus **1100**. In this manner, the introduction of foreign material into the apparatus **1100** is minimized. This minimizes the possibility of foreign material clogging the various flow passages and valves of the apparatus **1100** and to ensure that no foreign material interferes with the expansion mandrel **1105** during the extrusion process.

In an exemplary embodiment, the apparatus **1100** includes a packer **1155** coupled to the bottom section of the shoe **1115** for fluidically isolating the region of the wellbore **1000** below the apparatus **1100**. In this manner, fluidic materials are prevented from entering the region of the wellbore **1000** below the apparatus **1100**. The packer **1155** may comprise any number of conventional commercially available packers such as, for example, EZ Drill Packer, EZ SV Packer or a drillable cement retainer. In an exemplary embodiment, the packer **1155** comprises an EZ Drill Packer available from Halliburton Energy Services in Dallas, Tex. In an alternative embodiment, a high gel strength pill may be set below the tie-back in place of the packer **1155**. In another alternative embodiment, the packer **1155** may be omitted.

In an exemplary embodiment, before or after positioning the apparatus **1100** within the wellbore **1000**, a couple of wellbore volumes are circulated in order to ensure that no foreign materials are located within the wellbore **1000** that might clog up the various flow passages and valves of the apparatus **1100** and to ensure that no foreign material interferes with the operation of the expansion mandrel **1105**.

As illustrated in FIG. **10c**, a hardenable fluidic sealing material **1160** is then pumped from a surface location into the fluid passage **1130**. The material **1160** then passes from the fluid passage **1130** into the interior region of the tubular member **1110** below the expandable mandrel **1105**. The material **1160** then passes from the interior region of the tubular member **1110** into the fluid passages **1140**. The material **1160** then exits the apparatus **1100** and fills the annular region between the exterior of the tubular member **1110** and the interior wall of the tubular liner **1008**. Continued pumping of the material **1160** causes the material **1160** to fill up at least a portion of the annular region.

The material **1160** may be pumped into the annular region at pressures and flow rates ranging, for example, from about 0 to 5,000 psi and 0 to 1,500 gallons/min, respectively. In an exemplary embodiment, the material **1160** is pumped into the annular region at pressures and flow rates specifically designed for the casing sizes being run, the annular spaces being filled, the pumping equipment available, and the properties of the fluid being pumped. The optimum flow rates and pressures are preferably calculated using conventional empirical methods.

The hardenable fluidic sealing material **1160** may comprise any number of conventional commercially available hardenable fluidic sealing materials such as, for example, slag mix, cement or epoxy. In an exemplary embodiment, the hardenable fluidic sealing material **1160** comprises blended cements specifically designed for well section being tied-back, available from Halliburton Energy Services in Dallas, Tex. in order to optimally provide proper support for the tubular member **1110** while maintaining optimum flow characteristics so as to minimize operational difficulties during the displacement of cement in the annular region. The optimum blend of the blended cements are preferably determined using conventional empirical methods.

The annular region may be filled with the material **1160** in sufficient quantities to ensure that, upon radial expansion of the tubular member **1110**, the annular region will be filled with material **1160**.

As illustrated in FIG. 10d, once the annular region has been adequately filled with material 1160, one or more plugs 1165, or other similar devices, preferably are introduced into the fluid passages 1140 thereby fluidically isolating the interior region of the tubular member 1110 from the annular region external to the tubular member 1110. In an exemplary embodiment, a non hardenable fluidic material 1161 is then pumped into the interior region of the tubular member 1110 below the mandrel 1105 causing the interior region to pressurize. In an exemplary embodiment, the one or more plugs 1165, or other similar devices, are introduced into the fluid passage 1140 with the introduction of the non hardenable fluidic material. In this manner, the amount of hardenable fluidic material within the interior of the tubular member 1110 is minimized.

As illustrated in FIG. 10e, once the interior region becomes sufficiently pressurized, the tubular member 1110 is extruded off of the expandable mandrel 1105. During the extrusion process, the expandable mandrel 1105 is raised out of the expanded portion of the tubular member 1110.

The plugs 1165 are preferably placed into the fluid passages 1140 by introducing the plugs 1165 into the fluid passage 1130 at a surface location in a conventional manner. The plugs 1165 may comprise any number of conventional commercially available devices from plugging a fluid passage such as, for example, brass balls, plugs, rubber balls, or darts modified in accordance with the teachings of the present disclosure.

In an exemplary embodiment, the plugs 1165 comprise low density rubber balls. In an alternative embodiment, for a shoe 1105 having a common central inlet passage, the plugs 1165 comprise a single latch down dart.

After placement of the plugs 1165 in the fluid passages 1140, the non hardenable fluidic material 1161 is preferably pumped into the interior region of the tubular member 1110 below the mandrel 1105 at pressures and flow rates ranging from approximately 500 to 9,000 psi and 40 to 3,000 gallons/min.

In an exemplary embodiment, after placement of the plugs 1165 in the fluid passages 1140, the non hardenable fluidic material 1161 is preferably pumped into the interior region of the tubular member 1110 below the mandrel 1105 at pressures and flow rates ranging from approximately 1200 to 8500 psi and 40 to 1250 gallons/min in order to optimally provide extrusion of typical tubulars.

For typical tubular members 1110, the extrusion of the tubular member 1110 off of the expandable mandrel 1105 will begin when the pressure of the interior region of the tubular member 1110 below the mandrel 1105 reaches, for example, approximately 1200 to 8500 psi. In an exemplary embodiment, the extrusion of the tubular member 1110 off of the expandable mandrel 1105 begins when the pressure of the interior region of the tubular member 1110 below the mandrel 1105 reaches approximately 1200 to 8500 psi.

During the extrusion process, the expandable mandrel 1105 may be raised out of the expanded portion of the tubular member 1110 at rates ranging, for example, from about 0 to 5 ft/sec. In an exemplary embodiment, during the extrusion process, the expandable mandrel 1105 is raised out of the expanded portion of the tubular member 1110 at rates ranging from about 0 to 2 ft/sec in order to optimally provide permit adjustment of operational parameters, and optimally ensure that the extrusion process will be completed before the material 1160 cures.

In an exemplary embodiment, at least a portion 1180 of the tubular member 1110 has an internal diameter less than the outside diameter of the mandrel 1105. In this manner,

when the mandrel 1105 expands the section 1180 of the tubular member 1110, at least a portion of the expanded section 1180 effects a seal with at least the wellbore casing 1012. In an exemplary embodiment, the seal is effected by compressing the seals 1016 between the expanded section 1180 and the wellbore casing 1012. In an exemplary embodiment, the contact pressure of the joint between the expanded section 1180 of the tubular member 1110 and the casing 1012 ranges from about 500 to 10,000 psi in order to optimally provide pressure to activate the sealing members 1145 and provide optimal resistance to ensure that the joint will withstand typical extremes of tensile and compressive loads.

In an exemplary embodiment, substantially all of the entire length of the tubular member 1110 has an internal diameter less than the outside diameter of the mandrel 1105. In this manner, extrusion of the tubular member 1110 by the mandrel 1105 results in contact between substantially all of the expanded tubular member 1110 and the existing casing 1008. In an exemplary embodiment, the contact pressure of the joint between the expanded tubular member 1110 and the casings 1008 and 1012 ranges from about 500 to 10,000 psi in order to optimally provide pressure to activate the sealing members 1145 and provide optimal resistance to ensure that the joint will withstand typical extremes of tensile and compressive loads.

In an exemplary embodiment, the operating pressure and flow rate of the material 1161 is controllably ramped down when the expandable mandrel 1105 reaches the upper end portion of the tubular member 1110. In this manner, the sudden release of pressure caused by the complete extrusion of the tubular member 1110 off of the expandable mandrel 1105 can be minimized. In an exemplary embodiment, the operating pressure of the fluidic material 1161 is reduced in a substantially linear fashion from 100% to about 10% during the end of the extrusion process beginning when the mandrel 1105 has completed approximately all but about 5 feet of the extrusion process.

Alternatively, or in combination, a shock absorber is provided in the support member 1150 in order to absorb the shock caused by the sudden release of pressure.

Alternatively, or in combination, a mandrel catching structure is provided in the upper end portion of the tubular member 1110 in order to catch or at least decelerate the mandrel 1105.

Referring to FIG. 10f, once the extrusion process is completed, the expandable mandrel 1105 is removed from the wellbore 1000. In an exemplary embodiment, either before or after the removal of the expandable mandrel 1105, the integrity of the fluidic seal of the joint between the upper portion of the tubular member 1110 and the upper portion of the tubular liner 1108 is tested using conventional methods. If the fluidic seal of the joint between the upper portion of the tubular member 1110 and the upper portion of the tubular liner 1108 is satisfactory, then the uncured portion of the material 1160 within the expanded tubular member 1110 is then removed in a conventional manner. The material 1160 within the annular region between the tubular member 1110 and the tubular liner 1008 is then allowed to cure.

As illustrated in FIG. 10f, preferably any remaining cured material 1160 within the interior of the expanded tubular member 1110 is then removed in a conventional manner using a conventional drill string. The resulting tie-back liner of casing 1170 includes the expanded tubular member 1110 and an outer annular layer 1175 of cured material 1160.

As illustrated in FIG. 10g, the remaining bottom portion of the apparatus 1100 comprising the shoe 1115 and packer

1155 is then preferably removed by drilling out the shoe **1115** and packer **1155** using conventional drilling methods.

In an exemplary embodiment, the apparatus **1100** incorporates the apparatus **900**.

Referring now to FIGS. **11a–11f**, an embodiment of an apparatus and method for hanging a tubular liner off of an existing wellbore casing will now be described. As illustrated in FIG. **11a**, a wellbore **1200** is positioned in a subterranean formation **1205**. The wellbore **1200** includes an existing cased section **1210** having a tubular casing **1215** and an annular outer layer of cement **1220**.

In order to extend the wellbore **1200** into the subterranean formation **1205**, a drill string **1225** is used in a well known manner to drill out material from the subterranean formation **1205** to form a new section **1230**.

As illustrated in FIG. **11b**, an apparatus **1300** for forming a wellbore casing in a subterranean formation is then positioned in the new section **1230** of the wellbore **100**. The apparatus **1300** preferably includes an expandable mandrel or pig **1305**, a tubular member **1310**, a shoe **1315**, a fluid passage **1320**, a fluid passage **1330**, a fluid passage **1335**, seals **1340**, a support member **1345**, and a wiper plug **1350**.

The expandable mandrel **1305** is coupled to and supported by the support member **1345**. The expandable mandrel **1305** is preferably adapted to controllably expand in a radial direction. The expandable mandrel **1305** may comprise any number of conventional commercially available expandable mandrels modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the expandable mandrel **1305** comprises a hydraulic expansion tool substantially as disclosed in U.S. Pat. No. 5,348,095, the disclosure of which is incorporated herein by reference, modified in accordance with the teachings of the present disclosure.

The tubular member **1310** is coupled to and supported by the expandable mandrel **1305**. The tubular member **1310** is preferably expanded in the radial direction and extruded off of the expandable mandrel **1305**. The tubular member **1310** may be fabricated from any number of materials such as, for example, Oilfield Country Tubular Goods (OCTG), 13 chromium steel tubing/casing or plastic casing. In an exemplary embodiment, the tubular member **1310** is fabricated from OCTG. The inner and outer diameters of the tubular member **1310** may range, for example, from approximately 0.75 to 47 inches and 1.05 to 48 inches, respectively. In an exemplary embodiment, the inner and outer diameters of the tubular member **1310** range from about 3 to 15.5 inches and 3.5 to 16 inches, respectively in order to optimally provide minimal telescoping effect in the most commonly encountered wellbore sizes.

In an exemplary embodiment, the tubular member **1310** includes an upper portion **1355**, an intermediate portion **1360**, and a lower portion **1365**. In an exemplary embodiment, the wall thickness and outer diameter of the upper portion **1355** of the tubular member **1310** range from about $\frac{3}{8}$ to $1\frac{1}{2}$ inches and $3\frac{1}{2}$ to 16 inches, respectively. In an exemplary embodiment, the wall thickness and outer diameter of the intermediate portion **1360** of the tubular member **1310** range from about 0.625 to 0.75 inches and 3 to 19 inches, respectively. In an exemplary embodiment, the wall thickness and outer diameter of the lower portion **1365** of the tubular member **1310** range from about $\frac{3}{8}$ to 1.5 inches and 3.5 to 16 inches, respectively.

In an exemplary embodiment, the outer diameter of the lower portion **1365** of the tubular member **1310** is significantly less than the outer diameters of the upper and intermediate portions, **1355** and **1360**, of the tubular member

1310 in order to optimize the formation of a concentric and overlapping arrangement of wellbore casings. In this manner, as will be described below with reference to FIGS. **12** and **13**, a wellhead system is optimally provided. In an exemplary embodiment, the formation of a wellhead system does not include the use of a hardenable fluidic material.

In an exemplary embodiment, the wall thickness of the intermediate section **1360** of the tubular member **1310** is less than or equal to the wall thickness of the upper and lower sections, **1355** and **1365**, of the tubular member **1310** in order to optimally facilitate the initiation of the extrusion process and optimally permit the placement of the apparatus in areas of the wellbore having tight clearances.

The tubular member **1310** preferably comprises a solid member. In an exemplary embodiment, the upper end portion **1355** of the tubular member **1310** is slotted, perforated, or otherwise modified to catch or slow down the mandrel **1305** when it completes the extrusion of tubular member **1310**. In an exemplary embodiment, the length of the tubular member **1310** is limited to minimize the possibility of buckling. For typical tubular member **1310** materials, the length of the tubular member **1310** is preferably limited to between about 40 to 20,000 feet in length.

The shoe **1315** is coupled to the tubular member **1310**. The shoe **1315** preferably includes fluid passages **1330** and **1335**. The shoe **1315** may comprise any number of conventional commercially available shoes such as, for example, Super Seal II float shoe, Super Seal II Down-Jet float shoe or guide shoe with a sealing sleeve for a latch-down plug modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the shoe **1315** comprises an aluminum down-jet guide shoe with a sealing sleeve for a latch-down plug available from Halliburton Energy Services in Dallas, Tex., modified in accordance with the teachings of the present disclosure, in order to optimally guide the tubular member **1310** into the wellbore **1200**, optimally fluidically isolate the interior of the tubular member **1310**, and optimally permit the complete drill out of the shoe **1315** upon the completion of the extrusion and cementing operations.

In an exemplary embodiment, the shoe **1315** further includes one or more side outlet ports in fluidic communication with the fluid passage **1330**. In this manner, the shoe **1315** preferably injects hardenable fluidic sealing material into the region outside the shoe **1315** and tubular member **1310**. In an exemplary embodiment, the shoe **1315** includes the fluid passage **1330** having an inlet geometry that can receive a fluidic sealing member. In this manner, the fluid passage **1330** can be sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage **1330**.

The fluid passage **1320** permits fluidic materials to be transported to and from the interior region of the tubular member **1310** below the expandable mandrel **1305**. The fluid passage **1320** is coupled to and positioned within the support member **1345** and the expandable mandrel **1305**. The fluid passage **1320** preferably extends from a position adjacent to the surface to the bottom of the expandable mandrel **1305**. The fluid passage **1320** is preferably positioned along a centerline of the apparatus **1300**. The fluid passage **1320** is preferably selected to transport materials such as cement, drilling mud, or epoxies at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to optimally provide sufficient operating pressures to circulate fluids at operationally efficient rates.

The fluid passage **1330** permits fluidic materials to be transported to and from the region exterior to the tubular member **1310** and shoe **1315**. The fluid passage **1330** is

coupled to and positioned within the shoe 1315 in fluidic communication with the interior region 1370 of the tubular member 1310 below the expandable mandrel 1305. The fluid passage 1330 preferably has a cross-sectional shape that permits a plug, or other similar device, to be placed in fluid passage 1330 to thereby block further passage of fluidic materials. In this manner, the interior region 1370 of the tubular member 1310 below the expandable mandrel 1305 can be fluidically isolated from the region exterior to the tubular member 1310. This permits the interior region 1370 of the tubular member 1310 below the expandable mandrel 1305 to be pressurized. The fluid passage 1330 is preferably positioned substantially along the centerline of the apparatus 1300.

The fluid passage 1330 is preferably selected to convey materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to optimally fill the annular region between the tubular member 1310 and the new section 1230 of the wellbore 1200 with fluidic materials. In an exemplary embodiment, the fluid passage 1330 includes an inlet geometry that can receive a dart and/or a ball sealing member. In this manner, the fluid passage 1330 can be sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage 1320.

The fluid passage 1335 permits fluidic materials to be transported to and from the region exterior to the tubular member 1310 and shoe 1315. The fluid passage 1335 is coupled to and positioned within the shoe 1315 in fluidic communication with the fluid passage 1330. The fluid passage 1335 is preferably positioned substantially along the centerline of the apparatus 1300. The fluid passage 1335 is preferably selected to convey materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to optimally fill the annular region between the tubular member 1310 and the new section 1230 of the wellbore 1200 with fluidic materials.

The seals 1340 are coupled to and supported by the upper end portion 1355 of the tubular member 1310. The seals 1340 are further positioned on an outer surface of the upper end portion 1355 of the tubular member 1310. The seals 1340 permit the overlapping joint between the lower end portion of the casing 1215 and the upper portion 1355 of the tubular member 1310 to be fluidically sealed. The seals 1340 may comprise any number of conventional commercially available seals such as, for example, lead, rubber, Teflon, or epoxy seals modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the seals 1340 comprise seals molded from Stratalock epoxy available from Halliburton Energy Services in Dallas, Tex. in order to optimally provide a hydraulic seal in the annulus of the overlapping joint while also creating optimal load bearing capability to withstand typical tensile and compressive loads.

In an exemplary embodiment, the seals 1340 are selected to optimally provide a sufficient frictional force to support the expanded tubular member 1310 from the existing casing 1215. In an exemplary embodiment, the frictional force provided by the seals 1340 ranges from about 1,000 to 1,000,000 lbf in order to optimally support the expanded tubular member 1310.

The support member 1345 is coupled to the expandable mandrel 1305, tubular member 1310, shoe 1315, and seals 1340. The support member 1345 preferably comprises an annular member having sufficient strength to carry the apparatus 1300 into the new section 1230 of the wellbore

1200. In an exemplary embodiment, the support member 1345 further includes one or more conventional centralizers (not illustrated) to help stabilize the tubular member 1310.

In an exemplary embodiment, the support member 1345 is thoroughly cleaned prior to assembly to the remaining portions of the apparatus 1300. In this manner, the introduction of foreign material into the apparatus 1300 is minimized. This minimizes the possibility of foreign material clogging the various flow passages and valves of the apparatus 1300 and to ensure that no foreign material interferes with the expansion process.

The wiper plug 1350 is coupled to the mandrel 1305 within the interior region 1370 of the tubular member 1310. The wiper plug 1350 includes a fluid passage 1375 that is coupled to the fluid passage 1320. The wiper plug 1350 may comprise one or more conventional commercially available wiper plugs such as, for example, Multiple Stage Cementer latch-down plugs, Omega latch-down plugs or three-wiper latch-down plug modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the wiper plug 1350 comprises a Multiple Stage Cementer latch-down plug available from Halliburton Energy Services in Dallas, Tex. modified in a conventional manner for releasable attachment to the expansion mandrel 1305.

In an exemplary embodiment, before or after positioning the apparatus 1300 within the new section 1230 of the wellbore 1200, a couple of wellbore volumes are circulated in order to ensure that no foreign materials are located within the wellbore 1200 that might clog up the various flow passages and valves of the apparatus 1300 and to ensure that no foreign material interferes with the extrusion process.

As illustrated in FIG. 11c, a hardenable fluidic sealing material 1380 is then pumped from a surface location into the fluid passage 1320. The material 1380 then passes from the fluid passage 1320, through the fluid passage 1375, and into the interior region 1370 of the tubular member 1310 below the expandable mandrel 1305. The material 1380 then passes from the interior region 1370 into the fluid passage 1330. The material 1380 then exits the apparatus 1300 via the fluid passage 1335 and fills the annular region 1390 between the exterior of the tubular member 1310 and the interior wall of the new section 1230 of the wellbore 1200. Continued pumping of the material 1380 causes the material 1380 to fill up at least a portion of the annular region 1390.

The material 1380 may be pumped into the annular region 1390 at pressures and flow rates ranging, for example, from about 0 to 5000 psi and 0 to 1,500 gallons/min, respectively. In an exemplary embodiment, the material 1380 is pumped into the annular region 1390 at pressures and flow rates ranging from about 0 to 5000 psi and 0 to 1,500 gallons/min, respectively, in order to optimally fill the annular region between the tubular member 1310 and the new section 1230 of the wellbore 1200 with the hardenable fluidic sealing material 1380.

The hardenable fluidic sealing material 1380 may comprise any number of conventional commercially available hardenable fluidic sealing materials such as, for example, slag mix, cement or epoxy. In an exemplary embodiment, the hardenable fluidic sealing material 1380 comprises blended cements designed specifically for the well section being drilled and available from Halliburton Energy Services in order to optimally provide support for the tubular member 1310 during displacement of the material 1380 in the annular region 1390. The optimum blend of the cement is preferably determined using conventional empirical methods.

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The annular region 1390 preferably is filled with the material 1380 in sufficient quantities to ensure that, upon radial expansion of the tubular member 1310, the annular region 1390 of the new section 1230 of the wellbore 1200 will be filled with material 1380.

As illustrated in FIG. 11d, once the annular region 1390 has been adequately filled with material 1380, a wiper dart 1395, or other similar device, is introduced into the fluid passage 1320. The wiper dart 1395 is preferably pumped through the fluid passage 1320 by a non hardenable fluidic material 1381. The wiper dart 1395 then preferably engages the wiper plug 1350.

As illustrated in FIG. 11e, in an exemplary embodiment, engagement of the wiper dart 1395 with the wiper plug 1350 causes the wiper plug 1350 to decouple from the mandrel 1305. The wiper dart 1395 and wiper plug 1350 then preferably will lodge in the fluid passage 1330, thereby blocking fluid flow through the fluid passage 1330, and fluidically isolating the interior region 1370 of the tubular member 1310 from the annular region 1390. In an exemplary embodiment, the non hardenable fluidic material 1381 is then pumped into the interior region 1370 causing the interior region 1370 to pressurize. Once the interior region 1370 becomes sufficiently pressurized, the tubular member 1310 is extruded off of the expandable mandrel 1305. During the extrusion process, the expandable mandrel 1305 is raised out of the expanded portion of the tubular member 1310 by the support member 1345.

The wiper dart 1395 is preferably placed into the fluid passage 1320 by introducing the wiper dart 1395 into the fluid passage 1320 at a surface location in a conventional manner. The wiper dart 1395 may comprise any number of conventional commercially available devices from plugging a fluid passage such as, for example, Multiple Stage Cementer latch-down plugs, Omega latch-down plugs or three wiper latch-down plug/dart modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the wiper dart 1395 comprises a three wiper latch-down plug modified to latch and seal in the Multiple Stage Cementer latch down plug 1350. The three wiper latch-down plug is available from Halliburton Energy Services in Dallas, Tex.

After blocking the fluid passage 1330 using the wiper plug 1330 and wiper dart 1395, the non hardenable fluidic material 1381 may be pumped into the interior region 1370 at pressures and flow rates ranging, for example, from approximately 0 to 5000 psi and 0 to 1,500 gallons/min in order to optimally extrude the tubular member 1310 off of the mandrel 1305. In this manner, the amount of hardenable fluidic material within the interior of the tubular member 1310 is minimized.

In an exemplary embodiment, after blocking the fluid passage 1330, the non hardenable fluidic material 1381 is preferably pumped into the interior region 1370 at pressures and flow rates ranging from approximately 500 to 9,000 psi and 40 to 3,000 gallons/min in order to optimally provide operating pressures to maintain the expansion process at rates sufficient to permit adjustments to be made in operating parameters during the extrusion process.

For typical tubular members 1310, the extrusion of the tubular member 1310 off of the expandable mandrel 1305 will begin when the pressure of the interior region 1370 reaches, for example, approximately 500 to 9,000 psi. In an exemplary embodiment, the extrusion of the tubular member 1310 off of the expandable mandrel 1305 is a function of the tubular member diameter, wall thickness of the tubular member, geometry of the mandrel, the type of lubricant, the

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composition of the shoe and tubular member, and the yield strength of the tubular member. The optimum flow rate and operating pressures are preferably determined using conventional empirical methods.

During the extrusion process, the expandable mandrel 1305 may be raised out of the expanded portion of the tubular member 1310 at rates ranging, for example, from about 0 to 5 ft/sec. In an exemplary embodiment, during the extrusion process, the expandable mandrel 1305 is raised out of the expanded portion of the tubular member 1310 at rates ranging from about 0 to 2 ft/sec in order to optimally provide an efficient process, optimally permit operator adjustment of operation parameters, and ensure optimal completion of the extrusion process before curing of the material 1380.

When the upper end portion 1355 of the tubular member 1310 is extruded off of the expandable mandrel 1305, the outer surface of the upper end portion 1355 of the tubular member 1310 will preferably contact the interior surface of the lower end portion of the casing 1215 to form an fluid tight overlapping joint. The contact pressure of the overlapping joint may range, for example, from approximately 50 to 20,000 psi. In an exemplary embodiment, the contact pressure of the overlapping joint ranges from approximately 400 to 10,000 psi in order to optimally provide contact pressure sufficient to ensure annular sealing and provide enough resistance to withstand typical tensile and compressive loads. In an exemplary embodiment, the sealing members 1340 will ensure an adequate fluidic and gaseous seal in the overlapping joint.

In an exemplary embodiment, the operating pressure and flow rate of the non hardenable fluidic material 1381 is controllably ramped down when the expandable mandrel 1305 reaches the upper end portion 1355 of the tubular member 1310. In this manner, the sudden release of pressure caused by the complete extrusion of the tubular member 1310 off of the expandable mandrel 1305 can be minimized. In an exemplary embodiment, the operating pressure is reduced in a substantially linear fashion from 100% to about 10% during the end of the extrusion process beginning when the mandrel 1305 has completed approximately all but about 5 feet of the extrusion process.

Alternatively, or in combination, a shock absorber is provided in the support member 1345 in order to absorb the shock caused by the sudden release of pressure.

Alternatively, or in combination, a mandrel catching structure is provided in the upper end portion 1355 of the tubular member 1310 in order to catch or at least decelerate the mandrel 1305.

Once the extrusion process is completed, the expandable mandrel 1305 is removed from the wellbore 1200. In an exemplary embodiment, either before or after the removal of the expandable mandrel 1305, the integrity of the fluidic seal of the overlapping joint between the upper portion 1355 of the tubular member 1310 and the lower portion of the casing 1215 is tested using conventional methods. If the fluidic seal of the overlapping joint between the upper portion 1355 of the tubular member 1310 and the lower portion of the casing 1215 is satisfactory, then the uncured portion of the material 1380 within the expanded tubular member 1310 is then removed in a conventional manner. The material 1380 within the annular region 1390 is then allowed to cure.

As illustrated in FIG. 11f, preferably any remaining cured material 1380 within the interior of the expanded tubular member 1310 is then removed in a conventional manner using a conventional drill string. The resulting new section of casing 1400 includes the expanded tubular member 1310 and an outer annular layer 1405 of cured material 305. The

bottom portion of the apparatus **1300** comprising the shoe **1315** may then be removed by drilling out the shoe **1315** using conventional drilling methods.

Referring now to FIGS. **12** and **13**, an exemplary embodiment of a wellhead system **1500** formed using one or more of the apparatus and processes described above with reference to FIGS. **1–11f** will be described. The wellhead system **1500** preferably includes a conventional Christmas tree/drilling spool assembly **1505**, a thick wall casing **1510**, an annular body of cement **1515**, an outer casing **1520**, an annular body of cement **1525**, an intermediate casing **1530**, and an inner casing **1535**.

The Christmas tree/drilling spool assembly **1505** may comprise any number of conventional Christmas tree/drilling spool assemblies such as, for example, the SS-15 Subsea Wellhead System, Spool Tree Subsea Production System or the Compact Wellhead System available from suppliers such as Dril-Quip, Cameron or Breda, modified in accordance with the teachings of the present disclosure. The drilling spool assembly **1505** is preferably operably coupled to the thick wall casing **1510** and/or the outer casing **1520**. The assembly **1505** may be coupled to the thick wall casing **1510** and/or outer casing **1520**, for example, by welding, a threaded connection or made from single stock. In an exemplary embodiment, the assembly **1505** is coupled to the thick wall casing **1510** and/or outer casing **1520** by welding.

The thick wall casing **1510** is positioned in the upper end of a wellbore **1540**. In an exemplary embodiment, at least a portion of the thick wall casing **1510** extends above the surface **1545** in order to optimally provide easy access and attachment to the Christmas tree/drilling spool assembly **1505**. The thick wall casing **1510** is preferably coupled to the Christmas tree/drilling spool assembly **1505**, the annular body of cement **1515**, and the outer casing **1520**.

The thick wall casing **1510** may comprise any number of conventional commercially available high strength wellbore casings such as, for example, Oilfield Country Tubular Goods, titanium tubing or stainless steel tubing. In an exemplary embodiment, the thick wall casing **1510** comprises Oilfield Country Tubular Goods available from various foreign and domestic steel mills. In an exemplary embodiment, the thick wall casing **1510** has a yield strength of about 40,000 to 135,000 psi in order to optimally provide maximum burst, collapse, and tensile strengths. In an exemplary embodiment, the thick wall casing **1510** has a failure strength in excess of about 5,000 to 20,000 psi in order to optimally provide maximum operating capacity and resistance to degradation of capacity after being drilled through for an extended time period.

The annular body of cement **1515** provides support for the thick wall casing **1510**. The annular body of cement **1515** may be provided using any number of conventional processes for forming an annular body of cement in a wellbore. The annular body of cement **1515** may comprise any number of conventional cement mixtures.

The outer casing **1520** is coupled to the thick wall casing **1510**. The outer casing **1520** may be fabricated from any number of conventional commercially available tubular members modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the outer casing **1520** comprises any one of the expandable tubular members described above with reference to FIGS. **1–11f**.

In an exemplary embodiment, the outer casing **1520** is coupled to the thick wall casing **1510** by expanding the outer casing **1520** into contact with at least a portion of the interior surface of the thick wall casing **1510** using any one of the embodiments of the processes and apparatus described

above with reference to FIGS. **1–11f**. In an alternative embodiment, substantially all of the overlap of the outer casing **1520** with the thick wall casing **1510** contacts with the interior surface of the thick wall casing **1510**.

The contact pressure of the interface between the outer casing **1520** and the thick wall casing **1510** may range, for example, from about 500 to 10,000 psi. In an exemplary embodiment, the contact pressure between the outer casing **1520** and the thick wall casing **1510** ranges from about 500 to 10,000 psi in order to optimally activate the pressure activated sealing members and to ensure that the overlapping joint will optimally withstand typical extremes of tensile and compressive loads that are experienced during drilling and production operations.

As illustrated in FIG. **13**, in an exemplary embodiment, the upper end of the outer casing **1520** includes one or more sealing members **1550** that provide a gaseous and fluidic seal between the expanded outer casing **1520** and the interior wall of the thick wall casing **1510**. The sealing members **1550** may comprise any number of conventional commercially available seals such as, for example, lead, plastic, rubber, Teflon or epoxy, modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the sealing members **1550** comprise seals molded from StrataLock epoxy available from Halliburton Energy Services in order to optimally provide an hydraulic seal and a load bearing interference fit between the tubular members. In an exemplary embodiment, the contact pressure of the interface between the thick wall casing **1510** and the outer casing **1520** ranges from about 500 to 10,000 psi in order to optimally activate the sealing members **1550** and also optimally ensure that the joint will withstand the typical operating extremes of tensile and compressive loads during drilling and production operations.

In an exemplary embodiment, the outer casing **1520** and the thick walled casing **1510** are combined in one unitary member.

The annular body of cement **1525** provides support for the outer casing **1520**. In an exemplary embodiment, the annular body of cement **1525** is provided using any one of the embodiments of the apparatus and processes described above with reference to FIGS. **1–11f**.

The intermediate casing **1530** may be coupled to the outer casing **1520** or the thick wall casing **1510**. In an exemplary embodiment, the intermediate casing **1530** is coupled to the thick wall casing **1510**. The intermediate casing **1530** may be fabricated from any number of conventional commercially available tubular members modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the intermediate casing **1530** comprises any one of the expandable tubular members described above with reference to FIGS. **1–11f**.

In an exemplary embodiment, the intermediate casing **1530** is coupled to the thick wall casing **1510** by expanding at least a portion of the intermediate casing **1530** into contact with the interior surface of the thick wall casing **1510** using any one of the processes and apparatus described above with reference to FIGS. **1–11f**. In an exemplary embodiment, the entire length of the overlap of the intermediate casing **1530** with the thick wall casing **1510** contacts the inner surface of the thick wall casing **1510**. The contact pressure of the interface between the intermediate casing **1530** and the thick wall casing **1510** may range, for example from about 500 to 10,000 psi. In an exemplary embodiment, the contact pressure between the intermediate casing **1530** and the thick wall casing **1510** ranges from about 500 to 10,000 psi in order to optimally activate the pressure activated sealing members

and to optimally ensure that the joint will withstand typical operating extremes of tensile and compressive loads experienced during drilling and production operations.

As illustrated in FIG. 13, in an exemplary embodiment, the upper end of the intermediate casing 1530 includes one or more sealing members 1560 that provide a gaseous and fluidic seal between the expanded end of the intermediate casing 1530 and the interior wall of the thick wall casing 1510. The sealing members 1560 may comprise any number of conventional commercially available seals such as, for example, plastic, lead, rubber, Teflon or epoxy, modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the sealing members 1560 comprise seals molded from StrataLock epoxy available from Halliburton Energy Services in order to optimally provide a hydraulic seal and a load bearing interference fit between the tubular members.

In an exemplary embodiment, the contact pressure of the interface between the expanded end of the intermediate casing 1530 and the thick wall casing 1510 ranges from about 500 to 10,000 psi in order to optimally activate the sealing members 1560 and also optimally ensure that the joint will withstand typical operating extremes of tensile and compressive loads that are experienced during drilling and production operations.

The inner casing 1535 may be coupled to the outer casing 1520 or the thick wall casing 1510. In an exemplary embodiment, the inner casing 1535 is coupled to the thick wall casing 1510. The inner casing 1535 may be fabricated from any number of conventional commercially available tubular members modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the inner casing 1535 comprises any one of the expandable tubular members described above with reference to FIGS. 1–11f.

In an exemplary embodiment, the inner casing 1535 is coupled to the outer casing 1520 by expanding at least a portion of the inner casing 1535 into contact with the interior surface of the thick wall casing 1510 using any one of the processes and apparatus described above with reference to FIGS. 1–11f. In an exemplary embodiment, the entire length of the overlap of the inner casing 1535 with the thick wall casing 1510 and intermediate casing 1530 contacts the inner surfaces of the thick wall casing 1510 and intermediate casing 1530. The contact pressure of the interface between the inner casing 1535 and the thick wall casing 1510 may range, for example from about 500 to 10,000 psi. In an exemplary embodiment, the contact pressure between the inner casing 1535 and the thick wall casing 1510 ranges from about 500 to 10,000 psi in order to optimally activate the pressure activated sealing members and to ensure that the joint will withstand typical extremes of tensile and compressive loads that are commonly experienced during drilling and production operations.

As illustrated in FIG. 13, in an exemplary embodiment, the upper end of the inner casing 1535 includes one or more sealing members 1570 that provide a gaseous and fluidic seal between the expanded end of the inner casing 1535 and the interior wall of the thick wall casing 1510. The sealing members 1570 may comprise any number of conventional commercially available seals such as, for example, lead, plastic, rubber, Teflon or epoxy, modified in accordance with the teachings of the present disclosure. In an exemplary embodiment, the sealing members 1570 comprise seals molded from StrataLock epoxy available from Halliburton Energy Services in order to optimally provide an hydraulic seal and a load bearing interference fit. In an exemplary embodiment, the contact pressure of the interface between

the expanded end of the inner casing 1535 and the thick wall casing 1510 ranges from about 500 to 10,000 psi in order to optimally activate the sealing members 1570 and also to optimally ensure that the joint will withstand typical operating extremes of tensile and compressive loads that are experienced during drilling and production operations.

In an alternative embodiment, the inner casings, 1520, 1530 and 1535, may be coupled to a previously positioned tubular member that is in turn coupled to the outer casing 1510. More generally, the exemplary embodiments may be used to form a concentric arrangement of tubular members.

Referring now to FIGS. 14a, 14b, 14c, 14d, 14e and 14f, an exemplary embodiment of a method and apparatus for forming a mono-diameter well casing within a subterranean formation will now be described.

As illustrated in FIG. 14a, a wellbore 1600 is positioned in a subterranean formation 1605. A first section of casing 1610 is formed in the wellbore 1600. The first section of casing 1610 includes an annular outer body of cement 1615 and a tubular section of casing 1620. The first section of casing 1610 may be formed in the wellbore 1600 using conventional methods and apparatus. In an exemplary embodiment, the first section of casing 1610 is formed using one or more of the methods and apparatus described above with reference to FIGS. 1–13 or below with reference to FIGS. 14b–17b.

The annular body of cement 1615 may comprise any number of conventional commercially available cement, or other load bearing, compositions. Alternatively, the body of cement 1615 may be omitted or replaced with an epoxy mixture.

The tubular section of casing 1620 preferably includes an upper end 1625 and a lower end 1630. Preferably, the lower end 1625 of the tubular section of casing 1620 includes an outer annular recess 1635 extending from the lower end 1630 of the tubular section of casing 1620. In this manner, the lower end 1625 of the tubular section of casing 1620 includes a thin walled section 1640. In an exemplary embodiment, an annular body 1645 of a compressible material is coupled to and at least partially positioned within the outer annular recess 1635. In this manner, the body of compressible material 1645 surrounds at least a portion of the thin walled section 1640.

The tubular section of casing 1620 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, stainless steel, automotive grade steel, carbon steel, low alloy steel, fiberglass or plastics. In an exemplary embodiment, the tubular section of casing 1620 is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills. The wall thickness of the thin walled section 1640 may range from about 0.125 to 1.5 inches. In an exemplary embodiment, the wall thickness of the thin walled section 1640 ranges from 0.25 to 1.0 inches in order to optimally provide burst strength for typical operational conditions while also minimizing resistance to radial expansion. The axial length of the thin walled section 1640 may range from about 120 to 2400 inches. In an exemplary embodiment, the axial length of the thin walled section 1640 ranges from about 240 to 480 inches.

The annular body of compressible material 1645 helps to minimize the radial force required to expand the tubular casing 1620 in the overlap with the tubular member 1715, helps to create a fluidic seal in the overlap with the tubular member 1715, and helps to create an interference fit sufficient to permit the tubular member 1715 to be supported by the tubular casing 1620. The annular body of compressible

material 1645 may comprise any number of commercially available compressible materials such as, for example, epoxy, rubber, Teflon, plastics or lead tubes. In an exemplary embodiment, the annular body of compressible material 1645 comprises StrataLock epoxy available from Halliburton Energy Services in order to optimally provide an hydraulic seal in the overlapped joint while also having compliance to thereby minimize the radial force required to expand the tubular casing. The wall thickness of the annular body of compressible material 1645 may range from about 0.05 to 0.75 inches. In an exemplary embodiment, the wall thickness of the annular body of compressible material 1645 ranges from about 0.1 to 0.5 inches in order to optimally provide a large compressible zone, minimize the radial forces required to expand the tubular casing, provide thickness for casing strings to provide contact with the inner surface of the wellbore upon radial expansion, and provide an hydraulic seal.

As illustrated in FIG. 14b, in order to extend the wellbore 1600 into the subterranean formation 1605, a drill string is used in a well known manner to drill out material from the subterranean formation 1605 to form a new wellbore section 1650. The diameter of the new section 1650 is preferably equal to or greater than the inner diameter of the tubular section of casing 1620.

As illustrated in FIG. 14c, an exemplary embodiment of an apparatus 1700 for forming a mono-diameter wellbore casing in a subterranean formation is then positioned in the new section 1650 of the wellbore 1600. The apparatus 1700 preferably includes a support member 1705, an expandable mandrel or pig 1710, a tubular member 1715, a shoe 1720, slips 1725, a fluid passage 1730, one or more fluid passages 1735, a fluid passage 1740, a first compressible annular body 1745, a second compressible annular body 1750, and a pressure chamber 1755.

The support member 1705 supports the apparatus 1700 within the wellbore 1600. The support member 1705 is coupled to the mandrel 1710, the tubular member 1715, the shoe 1720, and the slips 1725. The support member 1705 preferably comprises a substantially hollow tubular member. The fluid passage 1730 is positioned within the support member 1705. The fluid passages 1735 fluidically couple the fluid passage 1730 with the pressure chamber 1755. The fluid passage 1740 fluidically couples the fluid passage 1730 with the region outside of the apparatus 1700.

The support member 1705 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, stainless steel, low alloy steel, carbon steel, 13 chromium steel, fiberglass, or other high strength materials. In an exemplary embodiment, the support member 1705 is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills in order to optimally provide operational strength and facilitate the use of other standard oil exploration handling equipment. In an exemplary embodiment, at least a portion of the support member 1705 comprises coiled tubing or a drill pipe. In an exemplary embodiment, the support member 1705 includes a load shoulder 1820 for supporting the mandrel 1710 when the pressure chamber 1755 is unpressurized.

The mandrel 1710 is supported by and slidably coupled to the support member 1705 and the shoe 1720. The mandrel 1710 preferably includes an upper portion 1760 and a lower portion 1765. Preferably, the upper portion 1760 of the mandrel 1710 and the support member 1705 together define the pressure chamber 1755. Preferably, the lower portion

1765 of the mandrel 1710 includes an expansion member 1770 for radially expanding the tubular member 1715.

In an exemplary embodiment, the upper portion 1760 of the mandrel 1710 includes a tubular member 1775 having an inner diameter greater than an outer diameter of the support member 1705. In this manner, an annular pressure chamber 1755 is defined by and positioned between the tubular member 1775 and the support member 1705. The top 1780 of the tubular member 1775 preferably includes a bearing and a seal for sealing and supporting the top 1780 of the tubular member 1775 against the outer surface of the support member 1705. The bottom 1785 of the tubular member 1775 preferably includes a bearing and seal for sealing and supporting the bottom 1785 of the tubular member 1775 against the outer surface of the support member 1705 or shoe 1720. In this manner, the mandrel 1710 moves in an axial direction upon the pressurization of the pressure chamber 1755.

The lower portion 1765 of the mandrel 1710 preferably includes an expansion member 1770 for radially expanding the tubular member 1715 during the pressurization of the pressure chamber 1755. In an exemplary embodiment, the expansion member is expandable in the radial direction. In an exemplary embodiment, the inner surface of the lower portion 1765 of the mandrel 1710 mates with and slides with respect to the outer surface of the shoe 1720. The outer diameter of the expansion member 1770 may range from about 90 to 100% of the inner diameter of the tubular casing 1620. In an exemplary embodiment, the outer diameter of the expansion member 1770 ranges from about 95 to 99% of the inner diameter of the tubular casing 1620. The expansion member 1770 may be fabricated from any number of conventional commercially available materials such as, for example, machine tool steel, ceramics, tungsten carbide, titanium or other high strength alloys. In an exemplary embodiment, the expansion member 1770 is fabricated from D2 machine tool steel in order to optimally provide high strength and abrasion resistance.

The tubular member 1715 is coupled to and supported by the support member 1705 and slips 1725. The tubular member 1715 includes an upper portion 1790 and a lower portion 1795.

The upper portion 1790 of the tubular member 1715 preferably includes an inner annular recess 1800 that extends from the upper portion 1790 of the tubular member 1715. In this manner, at least a portion of the upper portion 1790 of the tubular member 1715 includes a thin walled section 1805. The first compressible annular member 1745 is preferably coupled to and supported by the outer surface of the upper portion 1790 of the tubular member 1715 in opposing relation to the thin wall section 1805.

The lower portion 1795 of the tubular member 1715 preferably includes an outer annular recess 1810 that extends from the lower portion 1790 of the tubular member 1715. In this manner, at least a portion of the lower portion 1795 of the tubular member 1715 includes a thin walled section 1815. The second compressible annular member 1750 is coupled to and at least partially supported within the outer annular recess 1810 of the upper portion 1790 of the tubular member 1715 in opposing relation to the thin wall section 1815.

The tubular member 1715 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, stainless steel, low alloy steel, carbon steel, automotive grade steel, fiberglass, 13 chrome steel, other high strength material, or high strength plastics. In an exemplary embodiment,

the tubular member **1715** is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills in order to optimally provide operational strength.

The shoe **1720** is supported by and coupled to the support member **1705**. The shoe **1720** preferably comprises a substantially hollow tubular member. In an exemplary embodiment, the wall thickness of the shoe **1720** is greater than the wall thickness of the support member **1705** in order to optimally provide increased radial support to the mandrel **1710**. The shoe **1720** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, stainless steel, automotive grade steel, low alloy steel, carbon steel, or high strength plastics. In an exemplary embodiment, the shoe **1720** is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills in order to optimally provide matching operational strength throughout the apparatus.

The slips **1725** are coupled to and supported by the support member **1705**. The slips **1725** removably support the tubular member **1715**. In this manner, during the radial expansion of the tubular member **1715**, the slips **1725** help to maintain the tubular member **1715** in a substantially stationary position by preventing upward movement of the tubular member **1715**.

The slips **1725** may comprise any number of conventional commercially available slips such as, for example, RTTS packer tungsten carbide mechanical slips, RTTS packer wicker type mechanical slips, or Model 3L retrievable bridge plug tungsten carbide upper mechanical slips. In an exemplary embodiment, the slips **1725** comprise RTTS packer tungsten carbide mechanical slips available from Halliburton Energy Services. In an exemplary embodiment, the slips **1725** are adapted to support axial forces ranging from about 0 to 750,000 lbf.

The fluid passage **1730** conveys fluidic materials from a surface location into the interior of the support member **1705**, the pressure chamber **1755**, and the region exterior of the apparatus **1700**. The fluid passage **1730** is fluidically coupled to the pressure chamber **1755** by the fluid passages **1735**. The fluid passage **1730** is fluidically coupled to the region exterior to the apparatus **1700** by the fluid passage **1740**.

In an exemplary embodiment, the fluid passage **1730** is adapted to convey fluidic materials such as, for example, cement, epoxy, drilling muds, slag mix, water or drilling gasses. In an exemplary embodiment, the fluid passage **1730** is adapted to convey fluidic materials at flow rate and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi. in order to optimally provide flow rates and operational pressures for the radial expansion processes.

The fluid passages **1735** convey fluidic material from the fluid passage **1730** to the pressure chamber **1755**. In an exemplary embodiment, the fluid passage **1735** is adapted to convey fluidic materials such as, for example, cement, epoxy, drilling muds, water or drilling gasses. In an exemplary embodiment, the fluid passage **1735** is adapted to convey fluidic materials at flow rate and pressures ranging from about 0 to 500 gallons/minute and 0 to 9,000 psi. in order to optimally provide operating pressures and flow rates for the various expansion processes.

The fluid passage **1740** conveys fluidic materials from the fluid passage **1730** to the region exterior to the apparatus **1700**. In an exemplary embodiment, the fluid passage **1740** is adapted to convey fluidic materials such as, for example, cement, epoxy, drilling muds, water or drilling gasses. In an exemplary embodiment, the fluid passage **1740** is adapted to

convey fluidic materials at flow rate and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi. in order to optimally provide operating pressures and flow rates for the various radial expansion processes.

In an exemplary embodiment, the fluid passage **1740** is adapted to receive a plug or other similar device for sealing the fluid passage **1740**. In this manner, the pressure chamber **1755** may be pressurized.

The first compressible annular body **1745** is coupled to and supported by an exterior surface of the upper portion **1790** of the tubular member **1715**. In an exemplary embodiment, the first compressible annular body **1745** is positioned in opposing relation to the thin walled section **1805** of the tubular member **1715**.

The first compressible annular body **1745** helps to minimize the radial force required to expand the tubular member **1715** in the overlap with the tubular casing **1620**, helps to create a fluidic seal in the overlap with the tubular casing **1620**, and helps to create an interference fit sufficient to permit the tubular member **1715** to be supported by the tubular casing **1620**. The first compressible annular body **1745** may comprise any number of commercially available compressible materials such as, for example, epoxy, rubber, Teflon, plastics, or hollow lead tubes. In an exemplary embodiment, the first compressible annular body **1745** comprises StrataLock epoxy available from Halliburton Energy Services in order to optimally provide an hydraulic seal, and compressibility to minimize the radial expansion force.

The wall thickness of the first compressible annular body **1745** may range from about 0.05 to 0.75 inches. In an exemplary embodiment, the wall thickness of the first compressible annular body **1745** ranges from about 0.1 to 0.5 inches in order to optimally (1) provide a large compressible zone, (2) minimize the required radial expansion force, (3) transfer the radial force to the tubular casings. As a result, in an exemplary embodiment, overall the outer diameter of the tubular member **1715** is approximately equal to the overall inner diameter of the tubular member **1620**.

The second compressible annular body **1750** is coupled to and at least partially supported within the outer annular recess **1810** of the tubular member **1715**. In an exemplary embodiment, the second compressible annular body **1750** is positioned in opposing relation to the thin walled section **1815** of the tubular member **1715**.

The second compressible annular body **1750** helps to minimize the radial force required to expand the tubular member **1715** in the overlap with another tubular member, helps to create a fluidic seal in the overlap of the tubular member **1715** with another tubular member, and helps to create an interference fit sufficient to permit another tubular member to be supported by the tubular member **1715**. The second compressible annular body **1750** may comprise any number of commercially available compressible materials such as, for example, epoxy, rubber, Teflon, plastics or hollow lead tubing. In an exemplary embodiment, the first compressible annular body **1750** comprises StrataLock epoxy available from Halliburton Energy Services in order to optimally provide an hydraulic seal in the overlapped joint, and compressibility that minimizes the radial expansion force.

The wall thickness of the second compressible annular body **1750** may range from about 0.05 to 0.75 inches. In an exemplary embodiment, the wall thickness of the second compressible annular body **1750** ranges from about 0.1 to 0.5 inches in order to optimally provide a large compressible

zone, and minimize the radial force required to expand the tubular member **1715** during subsequent radial expansion operations.

In an alternative embodiment, the outside diameter of the second compressible annular body **1750** is adapted to provide a seal against the surrounding formation thereby eliminating the need for an outer annular body of cement.

The pressure chamber **1755** is fluidly coupled to the fluid passage **1730** by the fluid passages **1735**. The pressure chamber **1755** is preferably adapted to receive fluidic materials such as, for example, drilling muds, water or drilling gases. In an exemplary embodiment, the pressure chamber **1755** is adapted to receive fluidic materials at flow rate and pressures ranging from about 0 to 500 gallons/minute and 0 to 9,000 psi. In order to optimally provide expansion pressure. In an exemplary embodiment, during pressurization of the pressure chamber **1755**, the operating pressure of the pressure chamber ranges from about 0 to 5,000 psi in order to optimally provide expansion pressure while minimizing the possibility of a catastrophic failure due to over pressurization.

As illustrated in FIG. **14d**, the apparatus **1700** is preferably positioned in the wellbore **1600** with the tubular member **1715** positioned in an overlapping relationship with the tubular casing **1620**. In an exemplary embodiment, the thin wall sections, **1640** and **1805**, of the tubular casing **1620** and tubular member **1725** are positioned in opposing overlapping relation. In this manner, the radial expansion of the tubular member **1725** will compress the thin wall sections, **1640** and **1805**, and annular compressible members, **1645** and **1745**, into intimate contact.

After positioning of the apparatus **1700**, a fluidic material **1825** is then pumped into the fluid passage **1730**. The fluidic material **1825** may comprise any number of conventional commercially available materials such as, for example, water, drilling mud, drilling gases, cement or epoxy. In an exemplary embodiment, the fluidic material **1825** comprises a hardenable fluidic sealing material such as, for example, cement in order to provide an outer annular body around the expanded tubular member **1715**.

The fluidic material **1825** may be pumped into the fluid passage **1730** at operating pressures and flow rates, for example, ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The fluidic material **1825** pumped into the fluid passage **1730** passes through the fluid passage **1740** and outside of the apparatus **1700**. The fluidic material **1825** fills the annular region **1830** between the outside of the apparatus **1700** and the interior walls of the wellbore **1600**.

As illustrated in FIG. **14e**, a plug **1835** is then introduced into the fluid passage **1730**. The plug **1835** lodges in the inlet to the fluid passage **1740** fluidly isolating and blocking off the fluid passage **1730**.

A fluidic material **1840** is then pumped into the fluid passage **1730**. The fluidic material **1840** may comprise any number of conventional commercially available materials such as, for example, water, drilling mud or drilling gases. In an exemplary embodiment, the fluidic material **1825** comprises a non-hardenable fluidic material such as, for example, drilling mud or drilling gases in order to optimally provide pressurization of the pressure chamber **1755**.

The fluidic material **1840** may be pumped into the fluid passage **1730** at operating pressures and flow rates ranging, for example, from about 0 to 9,000 psi and 0 to 500 gallons/minute. In an exemplary embodiment, the fluidic material **1840** is pumped into the fluid passage **1730** at operating pressures and flow rates ranging from about 500 to

5,000 psi and 0 to 500 gallons/minute in order to optimally provide operating pressures and flow rates for radial expansion.

The fluidic material **1840** pumped into the fluid passage **1730** passes through the fluid passages **1735** and into the pressure chamber **1755**. Continued pumping of the fluidic material **1840** pressurizes the pressure chamber **1755**. The pressurization of the pressure chamber **1755** causes the mandrel **1710** to move relative to the support member **1705** in the direction indicated by the arrows **1845**. In this manner, the mandrel **1710** will cause the tubular member **1715** to expand in the radial direction.

During the radial expansion process, the tubular member **1715** is prevented from moving in an upward direction by the slips **1725**. A length of the tubular member **1715** is then expanded in the radial direction through the pressurization of the pressure chamber **1755**. The length of the tubular member **1715** that is expanded during the expansion process will be proportional to the stroke length of the mandrel **1710**. Upon the completion of a stroke, the operating pressure of the pressure chamber **1755** is then reduced and the mandrel **1710** drops to its rest position with the tubular member **1715** supported by the mandrel **1715**. The position of the support member **1705** may be adjusted throughout the radial expansion process in order to maintain the overlapping relationship between the thin walled sections, **1640** and **1805**, of the tubular casing **1620** and tubular member **1715**. The stroking of the mandrel **1710** is then repeated, as necessary, until the thin walled section **1805** of the tubular member **1715** is expanded into the thin walled section **1640** of the tubular casing **1620**.

In an exemplary embodiment, during the final stroke of the mandrel **1710**, the slips **1725** are positioned as close as possible to the thin walled section **1805** of the tubular member **1715** in order to minimize slippage between the tubular member **1715** and tubular casing **1620** at the end of the radial expansion process. Alternatively, or in addition, the outside diameter of the first compressive annular member **1745** is selected to ensure sufficient interference fit with the tubular casing **1620** to prevent axial displacement of the tubular member **1715** during the final stroke. Alternatively, or in addition, the outside diameter of the second compressive annular body **1750** is large enough to provide an interference fit with the inside walls of the wellbore **1600** at an earlier point in the radial expansion process so as to prevent further axial displacement of the tubular member **1715**. In this final alternative, the interference fit is preferably selected to permit expansion of the tubular member **1715** by pulling the mandrel **1710** out of the wellbore **1600**, without having to pressurize the pressure chamber **1755**.

During the radial expansion process, the pressurized areas of the apparatus **1700** are limited to the fluid passages **1730** within the support member **1705** and the pressure chamber **1755** within the mandrel **1710**. No fluid pressure acts directly on the tubular member **1715**. This permits the use of operating pressures higher than the tubular member **1715** could normally withstand.

Once the tubular member **1715** has been completely expanded off of the mandrel **1710**, the support member **1705** and mandrel **1710** are removed from the wellbore **1600**. In an exemplary embodiment, the contact pressure between the deformed thin wall sections, **1640** and **1805**, and compressible annular members, **1645** and **1745**, ranges from about 400 to 10,000 psi in order to optimally support the tubular member **1715** using the tubular casing **1620**.

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In this manner, the tubular member **1715** is radially expanded into contact with the tubular casing **1620** by pressurizing the interior of the fluid passage **1730** and the pressure chamber **1755**.

As illustrated in FIG. **14f**, in an exemplary embodiment, once the tubular member **1715** is completely expanded in the radial direction by the mandrel **1710**, the support member **1705** and mandrel **1710** are removed from the wellbore **1600**. In an exemplary embodiment, the annular body of hardenable fluidic material is then allowed to cure to form a rigid outer annular body **1850**. In the case where the tubular member **1715** is slotted, the hardenable fluidic material will preferably permeate and envelop the expanded tubular member **1715**.

The resulting new section of wellbore casing **1855** includes the expanded tubular member **1715** and the rigid outer annular body **1850**. The overlapping joint **1860** between the tubular casing **1620** and the expanded tubular member **1715** includes the deformed thin wall sections, **1640** and **1805**, and the compressible annular bodies, **1645** and **1745**. The inner diameter of the resulting combined wellbore casings is substantially constant. In this manner, a mono-diameter wellbore casing is formed. This process of expanding overlapping tubular members having thin wall end portions with compressible annular bodies into contact can be repeated for the entire length of a wellbore. In this manner, a mono-diameter wellbore casing can be provided for thousands of feet in a subterranean formation.

Referring now to FIGS. **15**, **15a** and **15b**, an embodiment of an apparatus **1900** for expanding a tubular member will be described. The apparatus **1900** preferably includes a drillpipe **1905**, an innerstring adapter **1910**, a sealing sleeve **1915**, an inner sealing mandrel **1920**, an upper sealing head **1925**, a lower sealing head **1930**, an outer sealing mandrel **1935**, a load mandrel **1940**, an expansion cone **1945**, a mandrel launcher **1950**, a mechanical slip body **1955**, mechanical slips **1960**, drag blocks **1965**, casing **1970**, and fluid passages **1975**, **1980**, **1985**, and **1990**.

The drillpipe **1905** is coupled to the innerstring adapter **1910**. During operation of the apparatus **1900**, the drillpipe **1905** supports the apparatus **1900**. The drillpipe **1905** preferably comprises a substantially hollow tubular member or members. The drillpipe **1905** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular drillpipe, fiberglass or coiled tubing. In an exemplary embodiment, the drillpipe **1905** is fabricated from coiled tubing in order to facilitate the placement of the apparatus **1900** in non-vertical wellbores. The drillpipe **1905** may be coupled to the innerstring adapter **1910** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connectors, OCTG specialty type box and pin connectors, a ratchet-latch type connector or a standard box by pin connector. In an exemplary embodiment, the drillpipe **1905** is removably coupled to the innerstring adapter **1910** by a drillpipe connection.

The drillpipe **1905** preferably includes a fluid passage **1975** that is adapted to convey fluidic materials from a surface location into the fluid passage **1980**. In an exemplary embodiment, the fluid passage **1975** is adapted to convey fluidic materials such as, for example, cement, drilling mud, epoxy or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The innerstring adapter **1910** is coupled to the drill string **1905** and the sealing sleeve **1915**. The innerstring adapter **1910** preferably comprises a substantially hollow tubular

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member or members. The innerstring adapter **1910** may be fabricated from any number of conventional commercially available materials such as, for example, oil country tubular goods, low alloy steel, carbon steel, stainless steel or other high strength materials. In an exemplary embodiment, the innerstring adapter **1910** is fabricated from oilfield country tubular goods in order to optimally provide mechanical properties that closely match those of the drill string **1905**.

The innerstring adapter **1910** may be coupled to the drill string **1905** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connectors, oilfield country tubular goods specialty type threaded connectors, ratchet-latch type stab in connector, or a standard threaded connection. In an exemplary embodiment, the innerstring adapter **1910** is removably coupled to the drill pipe **1905** by a drillpipe connection. The innerstring adapter **1910** may be coupled to the sealing sleeve **1915** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connector, ratchet-latch type stab in connectors, or a standard threaded connection. In an exemplary embodiment, the innerstring adapter **1910** is removably coupled to the sealing sleeve **1915** by a standard threaded connection.

The innerstring adapter **1910** preferably includes a fluid passage **1980** that is adapted to convey fluidic materials from the fluid passage **1975** into the fluid passage **1985**. In an exemplary embodiment, the fluid passage **1980** is adapted to convey fluidic materials such as, for example, cement, drilling mud, epoxy, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The sealing sleeve **1915** is coupled to the innerstring adapter **1910** and the inner sealing mandrel **1920**. The sealing sleeve **1915** preferably comprises a substantially hollow tubular member or members. The sealing sleeve **1915** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, carbon steel, low alloy steel, stainless steel or other high strength materials. In an exemplary embodiment, the sealing sleeve **1915** is fabricated from oilfield country tubular goods in order to optimally provide mechanical properties that substantially match the remaining components of the apparatus **1900**.

The sealing sleeve **1915** may be coupled to the innerstring adapter **1910** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type stab in connection, or a standard threaded connection. In an exemplary embodiment, the sealing sleeve **1915** is removably coupled to the innerstring adapter **1910** by a standard threaded connection. The sealing sleeve **1915** may be coupled to the inner sealing mandrel **1920** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In an exemplary embodiment, the sealing sleeve **1915** is removably coupled to the inner sealing mandrel **1920** by a standard threaded connection.

The sealing sleeve **1915** preferably includes a fluid passage **1985** that is adapted to convey fluidic materials from the fluid passage **1980** into the fluid passage **1990**. In an exemplary embodiment, the fluid passage **1985** is adapted to convey fluidic materials such as, for example, cement,

drilling mud, epoxy or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The inner sealing mandrel 1920 is coupled to the sealing sleeve 1915 and the lower sealing head 1930. The inner sealing mandrel 1920 preferably comprises a substantially hollow tubular member or members. The inner sealing mandrel 1920 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, stainless steel, low alloy steel, carbon steel or other similar high strength materials. In an exemplary embodiment, the inner sealing mandrel 1920 is fabricated from stainless steel in order to optimally provide mechanical properties similar to the other components of the apparatus 1900 while also providing a smooth outer surface to support seals and other moving parts that can operate with minimal wear, corrosion and pitting.

The inner sealing mandrel 1920 may be coupled to the sealing sleeve 1915 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In an exemplary embodiment, the inner sealing mandrel 1920 is removably coupled to the sealing sleeve 1915 by a standard threaded connections. The inner sealing mandrel 1920 may be coupled to the lower sealing head 1930 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type stab in connectors or standard threaded connections. In an exemplary embodiment, the inner sealing mandrel 1920 is removably coupled to the lower sealing head 1930 by a standard threaded connections connection.

The inner sealing mandrel 1920 preferably includes a fluid passage 1990 that is adapted to convey fluidic materials from the fluid passage 1985 into the fluid passage 1995. In an exemplary embodiment, the fluid passage 1990 is adapted to convey fluidic materials such as, for example, cement, drilling mud, epoxy or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The upper sealing head 1925 is coupled to the outer sealing mandrel 1935 and the expansion cone 1945. The upper sealing head 1925 is also movably coupled to the outer surface of the inner sealing mandrel 1920 and the inner surface of the casing 1970. In this manner, the upper sealing head 1925, outer sealing mandrel 1935, and the expansion cone 1945 reciprocate in the axial direction. The radial clearance between the inner cylindrical surface of the upper sealing head 1925 and the outer surface of the inner sealing mandrel 1920 may range, for example, from about 0.025 to 0.05 inches. In an exemplary embodiment, the radial clearance between the inner cylindrical surface of the upper sealing head 1925 and the outer surface of the inner sealing mandrel 1920 ranges from about 0.005 to 0.01 inches in order to optimally provide clearance for pressure seal placement. The radial clearance between the outer cylindrical surface of the upper sealing head 1925 and the inner surface of the casing 1970 may range, for example, from about 0.025 to 0.375 inches. In an exemplary embodiment, the radial clearance between the outer cylindrical surface of the upper sealing head 1925 and the inner surface of the casing 1970 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 1945 as the expansion cone 1945 is upwardly moved inside the casing 1970.

The upper sealing head 1925 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The upper sealing head 1925 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, stainless steel, machine tool steel, or similar high strength materials. In an exemplary embodiment, the upper sealing head 1925 is fabricated from stainless steel in order to optimally provide high strength and smooth outer surfaces that are resistant to wear, galling, corrosion and pitting.

The inner surface of the upper sealing head 1925 preferably includes one or more annular sealing members 2000 for sealing the interface between the upper sealing head 1925 and the inner sealing mandrel 1920. The sealing members 2000 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In an exemplary embodiment, the sealing members 2000 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial motion.

In an exemplary embodiment, the upper sealing head 1925 includes a shoulder 2005 for supporting the upper sealing head 1925 on the lower sealing head 1930.

The upper sealing head 1925 may be coupled to the outer sealing mandrel 1935 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connections. In an exemplary embodiment, the upper sealing head 1925 is removably coupled to the outer sealing mandrel 1935 by a standard threaded connections. In an exemplary embodiment, the mechanical coupling between the upper sealing head 1925 and the outer sealing mandrel 1935 includes one or more sealing members 2010 for fluidically sealing the interface between the upper sealing head 1925 and the outer sealing mandrel 1935. The sealing members 2010 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In an exemplary embodiment, the sealing members 2010 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroking motion.

The lower sealing head 1930 is coupled to the inner sealing mandrel 1920 and the load mandrel 1940. The lower sealing head 1930 is also movably coupled to the inner surface of the outer sealing mandrel 1935. In this manner, the upper sealing head 1925 and outer sealing mandrel 1935 reciprocate in the axial direction. The radial clearance between the outer surface of the lower sealing head 1930 and the inner surface of the outer sealing mandrel 1935 may range, for example, from about 0.025 to 0.05 inches. In an exemplary embodiment, the radial clearance between the outer surface of the lower sealing head 1930 and the inner surface of the outer sealing mandrel 1935 ranges from about 0.005 to 0.010 inches in order to optimally provide a close tolerance having room for the installation of pressure seal rings.

The lower sealing head 1930 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The lower sealing head 1930 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, stainless steel, machine tool steel or other similar high strength materials. In an exemplary embodiment, the lower sealing head 1930 is fabricated from stainless steel in order to optimally provide high strength and resistance to wear, galling, corrosion, and pitting.

The outer surface of the lower sealing head **1930** preferably includes one or more annular sealing members **2015** for sealing the interface between the lower sealing head **1930** and the outer sealing mandrel **1935**. The sealing members **2015** may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In an exemplary embodiment, the sealing members **2015** comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The lower sealing head **1930** may be coupled to the inner sealing mandrel **1920** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding or a standard threaded connection. In an exemplary embodiment, the lower sealing head **1930** is removably coupled to the inner sealing mandrel **1920** by a standard threaded connection.

In an exemplary embodiment, the mechanical coupling between the lower sealing head **1930** and the inner sealing mandrel **1920** includes one or more sealing members **2020** for fluidically sealing the interface between the lower sealing head **1930** and the inner sealing mandrel **1920**. The sealing members **2020** may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In an exemplary embodiment, the sealing members **2020** comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial motion.

The lower sealing head **1930** may be coupled to the load mandrel **1940** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connections, welding, amorphous bonding or a standard threaded connection. In an exemplary embodiment, the lower sealing head **1930** is removably coupled to the load mandrel **1940** by a standard threaded connection. In an exemplary embodiment, the mechanical coupling between the lower sealing head **1930** and the load mandrel **1940** includes one or more sealing members **2025** for fluidically sealing the interface between the lower sealing head **1930** and the load mandrel **1940**. The sealing members **2025** may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In an exemplary embodiment, the sealing members **2025** comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

In an exemplary embodiment, the lower sealing head **1930** includes a throat passage **2040** fluidically coupled between the fluid passages **1990** and **1995**. The throat passage **2040** is preferably of reduced size and is adapted to receive and engage with a plug **2045**, or other similar device. In this manner, the fluid passage **1990** is fluidically isolated from the fluid passage **1995**. In this manner, the pressure chamber **2030** is pressurized.

The outer sealing mandrel **1935** is coupled to the upper sealing head **1925** and the expansion cone **1945**. The outer sealing mandrel **1935** is also movably coupled to the inner surface of the casing **1970** and the outer surface of the lower sealing head **1930**. In this manner, the upper sealing head **1925**, outer sealing mandrel **1935**, and the expansion cone **1945** reciprocate in the axial direction. The radial clearance between the outer surface of the outer sealing mandrel **1935** and the inner surface of the casing **1970** may range, for example, from about 0.025 to 0.375 inches. In an exemplary

embodiment, the radial clearance between the outer surface of the outer sealing mandrel **1935** and the inner surface of the casing **1970** ranges from about 0.025 to 0.125 inches in order to optimally provide maximum piston surface area to maximize the radial expansion force. The radial clearance between the inner surface of the outer sealing mandrel **1935** and the outer surface of the lower sealing head **1930** may range, for example, from about 0.025 to 0.05 inches. In an exemplary embodiment, the radial clearance between the inner surface of the outer sealing mandrel **1935** and the outer surface of the lower sealing head **1930** ranges from about 0.005 to 0.010 inches in order to optimally provide a minimum gap for the sealing elements to bridge and seal.

The outer sealing mandrel **1935** preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The outer sealing mandrel **1935** may be fabricated from any number of conventional commercially available materials such as, for example, low alloy steel, carbon steel, 13 chromium steel or stainless steel. In an exemplary embodiment, the outer sealing mandrel **1935** is fabricated from stainless steel in order to optimally provide maximum strength and minimum wall thickness while also providing resistance to corrosion, galling and pitting.

The outer sealing mandrel **1935** may be coupled to the upper sealing head **1925** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, standard threaded connections, or welding. In an exemplary embodiment, the outer sealing mandrel **1935** is removably coupled to the upper sealing head **1925** by a standard threaded connections connection. The outer sealing mandrel **1935** may be coupled to the expansion cone **1945** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connections connection, or welding. In an exemplary embodiment, the outer sealing mandrel **1935** is removably coupled to the expansion cone **1945** by a standard threaded connections connection.

The upper sealing head **1925**, the lower sealing head **1930**, the inner sealing mandrel **1920**, and the outer sealing mandrel **1935** together define a pressure chamber **2030**. The pressure chamber **2030** is fluidically coupled to the passage **1990** via one or more passages **2035**. During operation of the apparatus **1900**, the plug **2045** engages with the throat passage **2040** to fluidically isolate the fluid passage **1990** from the fluid passage **1995**. The pressure chamber **2030** is then pressurized which in turn causes the upper sealing head **1925**, outer sealing mandrel **1935**, and expansion cone **1945** to reciprocate in the axial direction. The axial motion of the expansion cone **1945** in turn expands the casing **1970** in the radial direction.

The load mandrel **1940** is coupled to the lower sealing head **1930** and the mechanical slip body **1955**. The load mandrel **1940** preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The load mandrel **1940** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the load mandrel **1940** is fabricated from oilfield country tubular goods in order to optimally provide high strength.

The load mandrel **1940** may be coupled to the lower sealing head **1930** using any number of conventional commercially available mechanical couplings such as, for

example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding or a standard threaded connection. In an exemplary embodiment, the load mandrel **1940** is removably coupled to the lower sealing head **1930** by a standard threaded connection. The load mandrel **1940** may be coupled to the mechanical slip body **1955** using any number of conventional commercially available mechanical couplings such as, for example, a drillpipe connection, oilfield country tubular goods specialty type threaded connections, welding, amorphous bonding, or a standard threaded connections connection. In an exemplary embodiment, the load mandrel **1940** is removably coupled to the mechanical slip body **1955** by a standard threaded connections connection.

The load mandrel **1940** preferably includes a fluid passage **1995** that is adapted to convey fluidic materials from the fluid passage **1990** to the region outside of the apparatus **1900**. In an exemplary embodiment, the fluid passage **1995** is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The expansion cone **1945** is coupled to the outer sealing mandrel **1935**. The expansion cone **1945** is also movably coupled to the inner surface of the casing **1970**. In this manner, the upper sealing head **1925**, outer sealing mandrel **1935**, and the expansion cone **1945** reciprocate in the axial direction. The reciprocation of the expansion cone **1945** causes the casing **1970** to expand in the radial direction.

The expansion cone **1945** preferably comprises an annular member having substantially cylindrical inner and conical outer surfaces. The outside radius of the outside conical surface may range, for example, from about 2 to 34 inches. In an exemplary embodiment, the outside radius of the outside conical surface ranges from about 3 to 28 inches in order to optimally provide cone dimensions for the typical range of tubular members.

The axial length of the expansion cone **1945** may range, for example, from about 2 to 8 times the largest outer diameter of the expansion cone **1945**. In an exemplary embodiment, the axial length of the expansion cone **1945** ranges from about 3 to 5 times the largest outer diameter of the expansion cone **1945** in order to optimally provide stability and centralization of the expansion cone **1945** during the expansion process. In an exemplary embodiment, the angle of attack of the expansion cone **1945** ranges from about 5 to 30 degrees in order to optimally balance friction forces with the desired amount of radial expansion. The expansion cone **1945** angle of attack will vary as a function of the operating parameters of the particular expansion operation.

The expansion cone **1945** may be fabricated from any number of conventional commercially available materials such as, for example, machine tool steel, ceramics, tungsten carbide, nitride steel, or other similar high strength materials. In an exemplary embodiment, the expansion cone **1945** is fabricated from D2 machine tool steel in order to optimally provide high strength and resistance to corrosion, wear, galling, and pitting. In an exemplary embodiment, the outside surface of the expansion cone **1945** has a surface hardness ranging from about 58 to 62 Rockwell C in order to optimally provide high strength and resist wear and galling.

The expansion cone **1945** may be coupled to the outside sealing mandrel **1935** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield tubular country goods

specialty type threaded connection, welding, amorphous bonding, or a standard threaded connections connection. In an exemplary embodiment, the expansion cone **1945** is coupled to the outside sealing mandrel **1935** using a standard threaded connections connection in order to optimally provide connector strength for the typical operating loading conditions while also permitting easy replacement of the expansion cone **1945**.

The mandrel launcher **1950** is coupled to the casing **1970**. The mandrel launcher **1950** comprises a tubular section of casing having a reduced wall thickness compared to the casing **1970**. In an exemplary embodiment, the wall thickness of the mandrel launcher is about 50 to 100% of the wall thickness of the casing **1970**. In this manner, the initiation of the radial expansion of the casing **1970** is facilitated, and the insertion of the larger outside diameter mandrel launcher **1950** into the wellbore and/or casing is facilitated.

The mandrel launcher **1950** may be coupled to the casing **1970** using any number of conventional mechanical couplings. The mandrel launcher **1950** may have a wall thickness ranging, for example, from about 0.15 to 1.5 inches. In an exemplary embodiment, the wall thickness of the mandrel launcher **1950** ranges from about 0.25 to 0.75 inches in order to optimally provide high strength with a small overall profile. The mandrel launcher **1950** may be fabricated from any number of conventional commercially available materials such as, for example, oil field tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the mandrel launcher **1950** is fabricated from oil field tubular goods of higher strength but lower wall thickness than the casing **1970** in order to optimally provide a thin walled container with approximately the same burst strength as the casing **1970**.

The mechanical slip body **1955** is coupled to the load mandrel **1970**, the mechanical slips **1960**, and the drag blocks **1965**. The mechanical slip body **1955** preferably comprises a tubular member having an inner passage **2050** fluidically coupled to the passage **1995**. In this manner, fluidic materials may be conveyed from the passage **2050** to a region outside of the apparatus **1900**.

The mechanical slip body **1955** may be coupled to the load mandrel **1940** using any number of conventional mechanical couplings. In an exemplary embodiment, the mechanical slip body **1955** is removably coupled to the load mandrel **1940** using a standard threaded connection in order to optimally provide high strength and permit the mechanical slip body **1955** to be easily replaced. The mechanical slip body **1955** may be coupled to the mechanical slips **1955** using any number of conventional mechanical couplings. In an exemplary embodiment, the mechanical slip body **1955** is removably coupled to the mechanical slips **1955** using threads and sliding steel retainer rings in order to optimally provide high strength coupling and also permit easy replacement of the mechanical slips **1955**. The mechanical slip body **1955** may be coupled to the drag blocks **1965** using any number of conventional mechanical couplings. In an exemplary embodiment, the mechanical slip body **1955** is removably coupled to the drag blocks **1965** using threaded connections and sliding steel retainer rings in order to optimally provide high strength and also permit easy replacement of the drag blocks **1965**.

The mechanical slips **1960** are coupled to the outside surface of the mechanical slip body **1955**. During operation of the apparatus **1900**, the mechanical slips **1960** prevent upward movement of the casing **1970** and mandrel launcher **1950**. In this manner, during the axial reciprocation of the

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expansion cone **1945**, the casing **1970** and mandrel launcher **1950** are maintained in a substantially stationary position. In this manner, the mandrel launcher **1950** and casing **1970** are expanded in the radial direction by the axial movement of the expansion cone **1945**.

The mechanical slips **1960** may comprise any number of conventional commercially available mechanical slips such as, for example, RTTS packer tungsten carbide mechanical slips, RTTS packer wicker type mechanical slips or Model 3L retrievable bridge plug tungsten carbide upper mechanical slips. In an exemplary embodiment, the mechanical slips **1960** comprise RTTS packer tungsten carbide mechanical slips available from Halliburton Energy Services in order to optimally provide resistance to axial movement of the casing **1970** during the expansion process.

The drag blocks **1965** are coupled to the outside surface of the mechanical slip body **1955**. During operation of the apparatus **1900**, the drag blocks **1965** prevent upward movement of the casing **1970** and mandrel launcher **1950**. In this manner, during the axial reciprocation of the expansion cone **1945**, the casing **1970** and mandrel launcher **1950** are maintained in a substantially stationary position. In this manner, the mandrel launcher **1950** and casing **1970** are expanded in the radial direction by the axial movement of the expansion cone **1945**.

The drag blocks **1965** may comprise any number of conventional commercially available mechanical slips such as, for example, RTTS packer tungsten carbide mechanical slips, RTTS packer wicker type mechanical slips or Model 3L retrievable bridge plug tungsten carbide upper mechanical slips. In an exemplary embodiment, the drag blocks **1965** comprise RTTS packer tungsten carbide mechanical slips available from Halliburton Energy Services in order to optimally provide resistance to axial movement of the casing **1970** during the expansion process.

The casing **1970** is coupled to the mandrel launcher **1950**. The casing **1970** is further removably coupled to the mechanical slips **1960** and drag blocks **1965**. The casing **1970** preferably comprises a tubular member. The casing **1970** may be fabricated from any number of conventional commercially available materials such as, for example, slotted tubulars, oil field country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the casing **1970** is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills in order to optimally provide high strength. In an exemplary embodiment, the upper end of the casing **1970** includes one or more sealing members positioned about the exterior of the casing **1970**.

During operation, the apparatus **1900** is positioned in a wellbore with the upper end of the casing **1970** positioned in an overlapping relationship within an existing wellbore casing. In order to minimize surge pressures within the borehole during placement of the apparatus **1900**, the fluid passage **1975** is preferably provided with one or more pressure relief passages. During the placement of the apparatus **1900** in the wellbore, the casing **1970** is supported by the expansion cone **1945**.

After positioning of the apparatus **1900** within the bore hole in an overlapping relationship with an existing section of wellbore casing, a first fluidic material is pumped into the fluid passage **1975** from a surface location. The first fluidic material is conveyed from the fluid passage **1975** to the fluid passages **1980**, **1985**, **1990**, **1995**, and **2050**. The first fluidic material will then exit the apparatus and fill the annular

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region between the outside of the apparatus **1900** and the interior walls of the bore hole.

The first fluidic material may comprise any number of conventional commercially available materials such as, for example, drilling mud, water, epoxy or cement. In an exemplary embodiment, the first fluidic material comprises a hardenable fluidic sealing material such as, for example, cement or epoxy. In this manner, a wellbore casing having an outer annular layer of a hardenable material may be formed.

The first fluidic material may be pumped into the apparatus **1900** at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi, and 0 to 3,000 gallons/minute. In an exemplary embodiment, the first fluidic material is pumped into the apparatus **1900** at operating pressures and flow rates ranging from about 0 to 4,500 psi and 0 to 3,000 gallons/minute in order to optimally provide operating pressures and flow rates for typical operating conditions.

At a predetermined point in the injection of the first fluidic material such as, for example, after the annular region outside of the apparatus **1900** has been filled to a predetermined level, a plug **2045**, dart, or other similar device is introduced into the first fluidic material. The plug **2045** lodges in the throat passage **2040** thereby fluidically isolating the fluid passage **1990** from the fluid passage **1995**.

After placement of the plug **2045** in the throat passage **2040**, a second fluidic material is pumped into the fluid passage **1975** in order to pressurize the pressure chamber **2030**. The second fluidic material may comprise any number of conventional commercially available materials such as, for example, water, drilling gases, drilling mud or lubricant. In an exemplary embodiment, the second fluidic material comprises a non-hardenable fluidic material such as, for example, water, drilling mud or lubricant in order to minimize frictional forces.

The second fluidic material may be pumped into the apparatus **1900** at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 4,500 gallons/minute. In an exemplary embodiment, the second fluidic material is pumped into the apparatus **1900** at operating pressures and flow rates ranging from about 0 to 3,500 psi, and 0 to 1,200 gallons/minute in order to optimally provide expansion of the casing **1970**.

The pressurization of the pressure chamber **2030** causes the upper sealing head **1925**, outer sealing mandrel **1935**, and expansion cone **1945** to move in an axial direction. As the expansion cone **1945** moves in the axial direction, the expansion cone **1945** pulls the mandrel launcher **1950** and drag blocks **1965** along, which sets the mechanical slips **1960** and stops further axial movement of the mandrel launcher **1950** and casing **1970**. In this manner, the axial movement of the expansion cone **1945** radially expands the mandrel launcher **1950** and casing **1970**.

Once the upper sealing head **1925**, outer sealing mandrel **1935**, and expansion cone **1945** complete an axial stroke, the operating pressure of the second fluidic material is reduced and the drill string **1905** is raised. This causes the inner sealing mandrel **1920**, lower sealing head **1930**, load mandrel **1940**, and mechanical slip body **1955** to move upward. This unsets the mechanical slips **1960** and permits the mechanical slips **1960** and drag blocks **1965** to be moved upward within the mandrel launcher and casing **1970**. When the lower sealing head **1930** contacts the upper sealing head **1925**, the second fluidic material is again pressurized and the radial expansion process continues. In this manner, the mandrel launcher **1950** and casing **1970** are radially expanded through repeated axial strokes of the upper sealing head

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1925, outer sealing mandrel 1935 and expansion cone 1945. Throughout the radial expansion process, the upper end of the casing 1970 is preferably maintained in an overlapping relation with an existing section of wellbore casing.

At the end of the radial expansion process, the upper end of the casing 1970 is expanded into intimate contact with the inside surface of the lower end of the existing wellbore casing. In an exemplary embodiment, the sealing members provided at the upper end of the casing 1970 provide a fluidic seal between the outside surface of the upper end of the casing 1970 and the inside surface of the lower end of the existing wellbore casing. In an exemplary embodiment, the contact pressure between the casing 1970 and the existing section of wellbore casing ranges from about 400 to 10,000 psi in order to optimally provide contact pressure for activating sealing members, provide optimal resistance to axial movement of the expanded casing 1970, and optimally support typical tensile and compressive loads.

In an exemplary embodiment, as the expansion cone 1945 nears the end of the casing 1970, the operating flow rate of the second fluidic material is reduced in order to minimize shock to the apparatus 1900. In an alternative embodiment, the apparatus 1900 includes a shock absorber for absorbing the shock created by the completion of the radial expansion of the casing 1970.

In an exemplary embodiment, the reduced operating pressure of the second fluidic material ranges from about 100 to 1,000 psi as the expansion cone 1945 nears the end of the casing 1970 in order to optimally provide reduced axial movement and velocity of the expansion cone 1945. In an exemplary embodiment, the operating pressure of the second fluidic material is reduced during the return stroke of the apparatus 1900 to the range of about 0 to 500 psi in order to minimize the resistance to the movement of the expansion cone 1945. In an exemplary embodiment, the stroke length of the apparatus 1900 ranges from about 10 to 45 feet in order to optimally provide equipment lengths that can be handled by typical oil well rigging equipment while also minimizing the frequency at which the expansion cone 1945 must be stopped so the apparatus 1900 can be re-stroked for further expansion operations.

In an alternative embodiment, at least a portion of the upper sealing head 1925 includes an expansion cone for radially expanding the mandrel launcher 1950 and casing 1970 during operation of the apparatus 1900 in order to increase the surface area of the casing 1970 acted upon during the radial expansion process. In this manner, the operating pressures can be reduced.

In an alternative embodiment, mechanical slips are positioned in an axial location between the sealing sleeve 1915 and the inner sealing mandrel 1920 in order to simplify the operation and assembly of the apparatus 1900.

Upon the complete radial expansion of the casing 1970, if applicable, the first fluidic material is permitted to cure within the annular region between the outside of the expanded casing 1970 and the interior walls of the wellbore. In the case where the expanded casing 1970 is slotted, the cured fluidic material will preferably permeate and envelop the expanded casing. In this manner, a new section of wellbore casing is formed within a wellbore. Alternatively, the apparatus 1900 may be used to join a first section of pipeline to an existing section of pipeline. Alternatively, the apparatus 1900 may be used to directly line the interior of a wellbore with a casing, without the use of an outer annular layer of a hardenable material. Alternatively, the apparatus 1900 may be used to expand a tubular support member in a hole.

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During the radial expansion process, the pressurized areas of the apparatus 1900 are limited to the fluid passages 1975, 1980, 1985, and 1990, and the pressure chamber 2030. No fluid pressure acts directly on the mandrel launcher 1950 and casing 1970. This permits the use of operating pressures higher than the mandrel launcher 1950 and casing 1970 could normally withstand.

Referring now to FIG. 16, an exemplary embodiment of an apparatus 2100 for forming a mono-diameter wellbore casing will be described. The apparatus 2100 preferably includes a drillpipe 2105, an innerstring adapter 2110, a sealing sleeve 2115, an inner sealing mandrel 2120, slips 2125, upper sealing head 2130, lower sealing head 2135, outer sealing mandrel 2140, load mandrel 2145, expansion cone 2150, and casing 2155.

The drillpipe 2105 is coupled to the innerstring adapter 2110. During operation of the apparatus 2100, the drillpipe 2105 supports the apparatus 2100. The drillpipe 2105 preferably comprises a substantially hollow tubular member or members. The drillpipe 2105 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength material. In an exemplary embodiment, the drillpipe 2105 is fabricated from coiled tubing in order to facilitate the placement of the apparatus 1900 in non-vertical wellbores. The drillpipe 2105 may be coupled to the innerstring adapter 2110 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type connection, or a standard threaded connection. In an exemplary embodiment, the drillpipe 2105 is removably coupled to the innerstring adapter 2110 by a drill pipe connection.

The drillpipe 2105 preferably includes a fluid passage 2160 that is adapted to convey fluidic materials from a surface location into the fluid passage 2165. In an exemplary embodiment, the fluid passage 2160 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The innerstring adapter 2110 is coupled to the drill string 2105 and the sealing sleeve 2115. The innerstring adapter 2110 preferably comprises a substantially hollow tubular member or members. The innerstring adapter 2110 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the innerstring adapter 2110 is fabricated from stainless steel in order to optimally provide high strength, low friction, and resistance to corrosion and wear.

The innerstring adapter 2110 may be coupled to the drill string 2105 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type connection or a standard threaded connection. In an exemplary embodiment, the innerstring adapter 2110 is removably coupled to the drill pipe 2105 by a drillpipe connection. The innerstring adapter 2110 may be coupled to the sealing sleeve 2115 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In an exemplary embodi-

ment, the innerstring adapter **2110** is removably coupled to the sealing sleeve **2115** by a standard threaded connection.

The innerstring adapter **2110** preferably includes a fluid passage **2165** that is adapted to convey fluidic materials from the fluid passage **2160** into the fluid passage **2170**. In an exemplary embodiment, the fluid passage **2165** is adapted to convey fluidic materials such as, for example, cement, epoxy, water drilling muds, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The sealing sleeve **2115** is coupled to the innerstring adapter **2110** and the inner sealing mandrel **2120**. The sealing sleeve **2115** preferably comprises a substantially hollow tubular member or members. The sealing sleeve **2115** may be fabricated from any number of conventional commercially available materials such as, for example, oil field tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the sealing sleeve **2115** is fabricated from stainless steel in order to optimally provide high strength, low friction surfaces, and resistance to corrosion, wear, galling, and pitting.

The sealing sleeve **2115** may be coupled to the innerstring adapter **2110** using any number of conventional commercially available mechanical couplings such as, for example, a standard threaded connection, oilfield country tubular goods specialty type threaded connections, welding, amorphous bonding, or a standard threaded connection. In an exemplary embodiment, the sealing sleeve **2115** is removably coupled to the innerstring adapter **2110** by a standard threaded connection. The sealing sleeve **2115** may be coupled to the inner sealing mandrel **2120** using any number of conventional commercially available mechanical couplings such as, for example, a standard threaded connection, oilfield country tubular goods specialty type threaded connections, welding, amorphous bonding, or a standard threaded connection. In an exemplary embodiment, the sealing sleeve **2115** is removably coupled to the inner sealing mandrel **2120** by a standard threaded connection.

The sealing sleeve **2115** preferably includes a fluid passage **2170** that is adapted to convey fluidic materials from the fluid passage **2165** into the fluid passage **2175**. In an exemplary embodiment, the fluid passage **2170** is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The inner sealing mandrel **2120** is coupled to the sealing sleeve **2115**, slips **2125**, and the lower sealing head **2135**. The inner sealing mandrel **2120** preferably comprises a substantially hollow tubular member or members. The inner sealing mandrel **2120** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the inner sealing mandrel **2120** is fabricated from stainless steel in order to optimally provide high strength, low friction surfaces, and corrosion and wear resistance.

The inner sealing mandrel **2120** may be coupled to the sealing sleeve **2115** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In an exemplary embodiment, the inner sealing mandrel **2120** is removably coupled to the sealing sleeve **2115** by a standard threaded connection. The standard

threaded connection provides high strength and permits easy replacement of components. The inner sealing mandrel **2120** may be coupled to the slips **2125** using any number of conventional commercially available mechanical couplings such as, for example, welding, amorphous bonding, or a standard threaded connection. In an exemplary embodiment, the inner sealing mandrel **2120** is removably coupled to the slips **2125** by a standard threaded connection. The inner sealing mandrel **2120** may be coupled to the lower sealing head **2135** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding or a standard threaded connection. In an exemplary embodiment, the inner sealing mandrel **2120** is removably coupled to the lower sealing head **2135** by a standard threaded connection.

The inner sealing mandrel **2120** preferably includes a fluid passage **2175** that is adapted to convey fluidic materials from the fluid passage **2170** into the fluid passage **2180**. In an exemplary embodiment, the fluid passage **2175** is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The slips **2125** are coupled to the outer surface of the inner sealing mandrel **2120**. During operation of the apparatus **2100**, the slips **2125** preferably maintain the casing **2155** in a substantially stationary position during the radial expansion of the casing **2155**. In an exemplary embodiment, the slips **2125** are activated using the fluid passages **2185** to convey pressurized fluid material into the slips **2125**.

The slips **2125** may comprise any number of commercially available hydraulic slips such as, for example, RTTS packer tungsten carbide hydraulic slips or Model 3L retrievable bridge plug hydraulic slips. In an exemplary embodiment, the slips **2125** comprise RTTS packer tungsten carbide hydraulic slips available from Halliburton Energy Services in order to optimally provide resistance to axial movement of the casing **2155** during the expansion process. In an exemplary embodiment, the slips include a fluid passage **2190**, pressure chamber **2195**, spring return **2200**, and slip member **2205**.

The slips **2125** may be coupled to the inner sealing mandrel **2120** using any number of conventional mechanical couplings. In an exemplary embodiment, the slips **2125** are removably coupled to the outer surface of the inner sealing mandrel **2120** by a thread connection in order to optimally provide interchangeability of parts.

The upper sealing head **2130** is coupled to the outer sealing mandrel **2140** and expansion cone **2150**. The upper sealing head **2130** is also movably coupled to the outer surface of the inner sealing mandrel **2120** and the inner surface of the casing **2155**. In this manner, the upper sealing head **2130** reciprocates in the axial direction. The radial clearance between the inner cylindrical surface of the upper sealing head **2130** and the outer surface of the inner sealing mandrel **2120** may range, for example, from about 0.025 to 0.05 inches. In an exemplary embodiment, the radial clearance between the inner cylindrical surface of the upper sealing head **2130** and the outer surface of the inner sealing mandrel **2120** ranges from about 0.005 to 0.010 inches in order to optimally provide a pressure seal. The radial clearance between the outer cylindrical surface of the upper sealing head **2130** and the inner surface of the casing **2155** may range, for example, from about 0.025 to 0.375 inches. In an exemplary embodiment, the radial clearance between the outer cylindrical surface of the upper sealing head **2130**

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and the inner surface of the casing **2155** ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone **2130** during axial movement of the expansion cone **2130**.

The upper sealing head **2130** preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The upper sealing head **2130** may be fabricated from any number of conventional commercially available materials such as, for example, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the upper sealing head **2130** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The inner surface of the upper sealing head **2130** preferably includes one or more annular sealing members **2210** for sealing the interface between the upper sealing head **2130** and the inner sealing mandrel **2120**. The sealing members **2210** may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In an exemplary embodiment, the sealing members **2210** comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

In an exemplary embodiment, the upper sealing head **2130** includes a shoulder **2215** for supporting the upper sealing head **2130** on the lower sealing head **2135**.

The upper sealing head **2130** may be coupled to the outer sealing mandrel **2140** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding or a standard threaded connection. In an exemplary embodiment, the upper sealing head **2130** is removably coupled to the outer sealing mandrel **2140** by a standard threaded connection. In an exemplary embodiment, the mechanical coupling between the upper sealing head **2130** and the outer sealing mandrel **2140** includes one or more sealing members **2220** for fluidically sealing the interface between the upper sealing head **2130** and the outer sealing mandrel **2140**. The sealing members **2220** may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In an exemplary embodiment, the sealing members **2220** comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The lower sealing head **2135** is coupled to the inner sealing mandrel **2120** and the load mandrel **2145**. The lower sealing head **2135** is also movably coupled to the inner surface of the outer sealing mandrel **2140**. In this manner, the upper sealing head **2130**, outer sealing mandrel **2140**, and expansion cone **2150** reciprocate in the axial direction. The radial clearance between the outer surface of the lower sealing head **2135** and the inner surface of the outer sealing mandrel **2140** may range, for example, from about 0.0025 to 0.05 inches. In an exemplary embodiment, the radial clearance between the outer surface of the lower sealing head **2135** and the inner surface of the outer sealing mandrel **2140** ranges from about 0.0025 to 0.05 inches in order to optimally provide minimal radial clearance.

The lower sealing head **2135** preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The lower sealing head **2135** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other

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similar high strength materials. In an exemplary embodiment, the lower sealing head **2135** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The outer surface of the lower sealing head **2135** preferably includes one or more annular sealing members **2225** for sealing the interface between the lower sealing head **2135** and the outer sealing mandrel **2140**. The sealing members **2225** may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In an exemplary embodiment, the sealing members **2225** comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The lower sealing head **2135** may be coupled to the inner sealing mandrel **2120** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding, or a standard threaded connection. In an exemplary embodiment, the lower sealing head **2135** is removably coupled to the inner sealing mandrel **2120** by a standard threaded connection. In an exemplary embodiment, the mechanical coupling between the lower sealing head **2135** and the inner sealing mandrel **2120** includes one or more sealing members **2230** for fluidically sealing the interface between the lower sealing head **2135** and the inner sealing mandrel **2120**. The sealing members **2230** may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In an exemplary embodiment, the sealing members **2230** comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The lower sealing head **2135** may be coupled to the load mandrel **2145** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In an exemplary embodiment, the lower sealing head **2135** is removably coupled to the load mandrel **2145** by a standard threaded connection. In an exemplary embodiment, the mechanical coupling between the lower sealing head **2135** and the load mandrel **2145** includes one or more sealing members **2235** for fluidically sealing the interface between the lower sealing head **2135** and the load mandrel **2145**. The sealing members **2235** may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In an exemplary embodiment, the sealing members **2235** comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

In an exemplary embodiment, the lower sealing head **2135** includes a throat passage **2240** fluidically coupled between the fluid passages **2175** and **2180**. The throat passage **2240** is preferably of reduced size and is adapted to receive and engage with a plug **2245**, or other similar device. In this manner, the fluid passage **2175** is fluidically isolated from the fluid passage **2180**. In this manner, the pressure chamber **2250** is pressurized.

The outer sealing mandrel **2140** is coupled to the upper sealing head **2130** and the expansion cone **2150**. The outer sealing mandrel **2140** is also movably coupled to the inner surface of the casing **2155** and the outer surface of the lower sealing head **2135**. In this manner, the upper sealing head **2130**, outer sealing mandrel **2140**, and the expansion cone

2150 reciprocate in the axial direction. The radial clearance between the outer surface of the outer sealing mandrel **2140** and the inner surface of the casing **2155** may range, for example, from about 0.025 to 0.375 inches. In an exemplary embodiment, the radial clearance between the outer surface of the outer sealing mandrel **2140** and the inner surface of the casing **2155** ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone **2130** during the expansion process. The radial clearance between the inner surface of the outer sealing mandrel **2140** and the outer surface of the lower sealing head **2135** may range, for example, from about 0.005 to 0.125 inches. In an exemplary embodiment, the radial clearance between the inner surface of the outer sealing mandrel **2140** and the outer surface of the lower sealing head **2135** ranges from about 0.005 to 0.010 inches in order to optimally provide minimal radial clearance.

The outer sealing mandrel **2140** preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The outer sealing mandrel **2140** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel, or other similar high strength materials. In an exemplary embodiment, the outer sealing mandrel **2140** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The outer sealing mandrel **2140** may be coupled to the upper sealing head **2130** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding or a standard threaded connection. In an exemplary embodiment, the outer sealing mandrel **2140** is removably coupled to the upper sealing head **2130** by a standard threaded connection. The outer sealing mandrel **2140** may be coupled to the expansion cone **2150** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In an exemplary embodiment, the outer sealing mandrel **2140** is removably coupled to the expansion cone **2150** by a standard threaded connection.

The upper sealing head **2130**, the lower sealing head **2135**, inner sealing mandrel **2120**, and the outer sealing mandrel **2140** together define a pressure chamber **2250**. The pressure chamber **2250** is fluidically coupled to the passage **2175** via one or more passages **2255**. During operation of the apparatus **2100**, the plug **2245** engages with the throat passage **2240** to fluidically isolate the fluid passage **2175** from the fluid passage **2180**. The pressure chamber **2250** is then pressurized which in turn causes the upper sealing head **2130**, outer sealing mandrel **2140**, and expansion cone **2150** to reciprocate in the axial direction. The axial motion of the expansion cone **2150** in turn expands the casing **2155** in the radial direction.

The load mandrel **2145** is coupled to the lower sealing head **2135**. The load mandrel **2145** preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The load mandrel **2145** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the load mandrel **2145** is fabricated from stainless

steel in order to optimally provide high strength, corrosion resistance, and low friction bearing surfaces.

The load mandrel **2145** may be coupled to the lower sealing head **2135** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding or a standard threaded connection. In an exemplary embodiment, the load mandrel **2145** is removably coupled to the lower sealing head **2135** by a standard threaded connection in order to optimally provide high strength and permit easy replacement of the load mandrel **2145**.

The load mandrel **2145** preferably includes a fluid passage **2180** that is adapted to convey fluidic materials from the fluid passage **2180** to the region outside of the apparatus **2100**. In an exemplary embodiment, the fluid passage **2180** is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The expansion cone **2150** is coupled to the outer sealing mandrel **2140**. The expansion cone **2150** is also movably coupled to the inner surface of the casing **2155**. In this manner, the upper sealing head **2130**, outer sealing mandrel **2140**, and the expansion cone **2150** reciprocate in the axial direction. The reciprocation of the expansion cone **2150** causes the casing **2155** to expand in the radial direction.

The expansion cone **2150** preferably comprises an annular member having substantially cylindrical inner and conical outer surfaces. The outside radius of the outside conical surface may range, for example, from about 2 to 34 inches. In an exemplary embodiment, the outside radius of the outside conical surface ranges from about 3 to 28 inches in order to optimally provide cone dimensions that are optimal for typical casings. The axial length of the expansion cone **2150** may range, for example, from about 2 to 6 times the largest outside diameter of the expansion cone **2150**. In an exemplary embodiment, the axial length of the expansion cone **2150** ranges from about 3 to 5 times the largest outside diameter of the expansion cone **2150** in order to optimally provide stability and centralization of the expansion cone **2150** during the expansion process. In an exemplary embodiment, the maximum outside diameter of the expansion cone **2150** is between about 90 to 100% of the inside diameter of the existing wellbore that the casing **2155** will be joined with. In an exemplary embodiment, the angle of attack of the expansion cone **2150** ranges from about 5 to 30 degrees in order to optimally balance friction forces and radial expansion forces. The optimal expansion cone **2150** angle of attack will vary as a function of the particular operating conditions of the expansion operation.

The expansion cone **2150** may be fabricated from any number of conventional commercially available materials such as, for example, machine tool steel, nitride steel, titanium, tungsten carbide, ceramics, or other similar high strength materials. In an exemplary embodiment, the expansion cone **2150** is fabricated from D2 machine tool steel in order to optimally provide high strength and resistance to wear and galling. In an exemplary embodiment, the outside surface of the expansion cone **2150** has a surface hardness ranging from about 58 to 62 Rockwell C in order to optimally provide resistance to wear.

The expansion cone **2150** may be coupled to the outside sealing mandrel **2140** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous

bonding or a standard threaded connection. In an exemplary embodiment, the expansion cone **2150** is coupled to the outside sealing mandrel **2140** using a standard threaded connection in order to optimally provide high strength and permit the expansion cone **2150** to be easily replaced.

The casing **2155** is removably coupled to the slips **2125** and expansion cone **2150**. The casing **2155** preferably comprises a tubular member. The casing **2155** may be fabricated from any number of conventional commercially available materials such as, for example, slotted tubulars, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength material. In an exemplary embodiment, the casing **2155** is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills in order to optimally provide high strength.

In an exemplary embodiment, the upper end **2260** of the casing **2155** includes a thin wall section **2265** and an outer annular sealing member **2270**. In an exemplary embodiment, the wall thickness of the thin wall section **2265** is about 50 to 100% of the regular wall thickness of the casing **2155**. In this manner, the upper end **2260** of the casing **2155** may be easily expanded and deformed into intimate contact with the lower end of an existing section of wellbore casing. In an exemplary embodiment, the lower end of the existing section of casing also includes a thin wall section. In this manner, the radial expansion of the thin walled section **2265** of casing **2155** into the thin walled section of the existing wellbore casing results in a wellbore casing having a substantially constant inside diameter.

The annular sealing member **2270** may be fabricated from any number of conventional commercially available sealing materials such as, for example, epoxy, rubber, metal or plastic. In an exemplary embodiment, the annular sealing member **2270** is fabricated from StrataLock epoxy in order to optimally provide compressibility and resistance to wear. The outside diameter of the annular sealing member **2270** preferably ranges from about 70 to 95% of the inside diameter of the lower section of the wellbore casing that the casing **2155** is joined to. In this manner, after expansion, the annular sealing member **2270** preferably provides a fluidic seal and also preferably provides sufficient frictional force with the inside surface of the existing section of wellbore casing during the radial expansion of the casing **2155** to support the casing **2155**.

In an exemplary embodiment, the lower end **2275** of the casing **2155** includes a thin wall section **2280** and an outer annular sealing member **2285**. In an exemplary embodiment, the wall thickness of the thin wall section **2280** is about 50 to 100% of the regular wall thickness of the casing **2155**. In this manner, the lower end **2275** of the casing **2155** may be easily expanded and deformed. Furthermore, in this manner, another section of casing may be easily joined with the lower end **2275** of the casing **2155** using a radial expansion process. In an exemplary embodiment, the upper end of the other section of casing also includes a thin wall section. In this manner, the radial expansion of the thin walled section of the upper end of the other casing into the thin walled section **2280** of the lower end of the casing **2155** results in a wellbore casing having a substantially constant inside diameter.

The annular sealing member **2285** may be fabricated from any number of conventional commercially available sealing materials such as, for example, epoxy, rubber, metal or plastic. In an exemplary embodiment, the annular sealing member **2285** is fabricated from StrataLock epoxy in order to optimally provide compressibility and wear resistance.

The outside diameter of the annular sealing member **2285** preferably ranges from about 70 to 95% of the inside diameter of the lower section of the existing wellbore casing that the casing **2155** is joined to. In this manner, the annular sealing member **2285** preferably provides a fluidic seal and also preferably provides sufficient frictional force with the inside wall of the wellbore during the radial expansion of the casing **2155** to support the casing **2155**.

During operation, the apparatus **2100** is preferably positioned in a wellbore with the upper end **2260** of the casing **2155** positioned in an overlapping relationship with the lower end of an existing wellbore casing. In an exemplary embodiment, the thin wall section **2265** of the casing **2155** is positioned in opposing overlapping relation with the thin wall section and outer annular sealing member of the lower end of the existing section of wellbore casing. In this manner, the radial expansion of the casing **2155** will compress the thin wall sections and annular compressible members of the upper end **2260** of the casing **2155** and the lower end of the existing wellbore casing into intimate contact. During the positioning of the apparatus **2100** in the wellbore, the casing **2155** is supported by the expansion cone **2150**.

After positioning of the apparatus **2100**, a first fluidic material is then pumped into the fluid passage **2160**. The first fluidic material may comprise any number of conventional commercially available materials such as, for example, drilling mud, water, epoxy, or cement. In an exemplary embodiment, the first fluidic material comprises a hardenable fluidic sealing material such as, for example, cement or epoxy in order to provide a hardenable outer annular body around the expanded casing **2155**.

The first fluidic material may be pumped into the fluid passage **2160** at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 3,000 gallons/minute. In an exemplary embodiment, the first fluidic material is pumped into the fluid passage **2160** at operating pressures and flow rates ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to optimally provide operational efficiency.

The first fluidic material pumped into the fluid passage **2160** passes through the fluid passages **2165**, **2170**, **2175**, **2180** and then outside of the apparatus **2100**. The first fluidic material then fills the annular region between the outside of the apparatus **2100** and the interior walls of the wellbore.

The plug **2245** is then introduced into the fluid passage **2160**. The plug **2245** lodges in the throat passage **2240** and fluidically isolates and blocks off the fluid passage **2175**. In an exemplary embodiment, a couple of volumes of a non-hardenable fluidic material are then pumped into the fluid passage **2160** in order to remove any hardenable fluidic material contained within and to ensure that none of the fluid passages are blocked.

A second fluidic material is then pumped into the fluid passage **2160**. The second fluidic material may comprise any number of conventional commercially available materials such as, for example, drilling mud, water, drilling gases, or lubricants. In an exemplary embodiment, the second fluidic material comprises a non-hardenable fluidic material such as, for example, water, drilling mud or lubricant in order to optimally provide pressurization of the pressure chamber **2250** and minimize frictional forces.

The second fluidic material may be pumped into the fluid passage **2160** at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 4,500 gallons/minute. In an exemplary embodiment, the second fluidic material is pumped into the fluid passage **2160** at operating pressures and flow rates ranging from about 0 to

3,500 psi and 0 to 1,200 gallons/minute in order to optimally provide operational efficiency.

The second fluidic material pumped into the fluid passage **2160** passes through the fluid passages **2165**, **2170**, and **2175** into the pressure chambers **2195** of the slips **2125**, and into the pressure chamber **2250**. Continued pumping of the second fluidic material pressurizes the pressure chambers **2195** and **2250**.

The pressurization of the pressure chambers **2195** causes the slip members **2205** to expand in the radial direction and grip the interior surface of the casing **2155**. The casing **2155** is then preferably maintained in a substantially stationary position.

The pressurization of the pressure chamber **2250** causes the upper sealing head **2130**, outer sealing mandrel **2140** and expansion cone **2150** to move in an axial direction relative to the casing **2155**. In this manner, the expansion cone **2150** will cause the casing **2155** to expand in the radial direction.

During the radial expansion process, the casing **2155** is prevented from moving in an upward direction by the slips **2125**. A length of the casing **2155** is then expanded in the radial direction through the pressurization of the pressure chamber **2250**. The length of the casing **2155** that is expanded during the expansion process will be proportional to the stroke length of the upper sealing head **2130**, outer sealing mandrel **2140**, and expansion cone **2150**.

Upon the completion of a stroke, the operating pressure of the second fluidic material is reduced and the upper sealing head **2130**, outer sealing mandrel **2140**, and expansion cone **2150** drop to their rest positions with the casing **2155** supported by the expansion cone **2150**. The position of the drillpipe **2105** is preferably adjusted throughout the radial expansion process in order to maintain the overlapping relationship between the thin walled sections of the lower end of the existing wellbore casing and the upper end of the casing **2155**. In an exemplary embodiment, the stroking of the expansion cone **2150** is then repeated, as necessary, until the thin walled section **2265** of the upper end **2260** of the casing **2155** is expanded into the thin walled section of the lower end of the existing wellbore casing. In this manner, a wellbore casing is formed including two adjacent sections of casing having a substantially constant inside diameter. This process may then be repeated for the entirety of the wellbore to provide a wellbore casing thousands of feet in length having a substantially constant inside diameter.

In an exemplary embodiment, during the final stroke of the expansion cone **2150**, the slips **2125** are positioned as close as possible to the thin walled section **2265** of the upper end of the casing **2155** in order minimize slippage between the casing **2155** and the existing wellbore casing at the end of the radial expansion process. Alternatively, or in addition, the outside diameter of the annular sealing member **2270** is selected to ensure sufficient interference fit with the inside diameter of the lower end of the existing casing to prevent axial displacement of the casing **2155** during the final stroke. Alternatively, or in addition, the outside diameter of the annular sealing member **2285** is selected to provide an interference fit with the inside walls of the wellbore at an earlier point in the radial expansion process so as to prevent further axial displacement of the casing **2155**. In this final alternative, the interference fit is preferably selected to permit expansion of the casing **2155** by pulling the expansion cone **2150** out of the wellbore, without having to pressurize the pressure chamber **2250**.

During the radial expansion process, the pressurized areas of the apparatus **2100** are limited to the fluid passages **2160**, **2165**, **2170**, and **2175**, the pressure chambers **2195** within

the slips **2125**, and the pressure chamber **2250**. No fluid pressure acts directly on the casing **2155**. This permits the use of operating pressures higher than the casing **2155** could normally withstand.

Once the casing **2155** has been completely expanded off of the expansion cone **2150**, remaining portions of the apparatus **2100** are removed from the wellbore. In an exemplary embodiment, the contact pressure between the deformed thin wall sections and compressible annular members of the lower end of the existing casing and the upper end **2260** of the casing **2155** ranges from about 500 to 40,000 psi in order to optimally support the casing **2155** using the existing wellbore casing.

In this manner, the casing **2155** is radially expanded into contact with an existing section of casing by pressurizing the interior fluid passages **2160**, **2165**, **2170**, and **2175** and the pressure chamber **2250** of the apparatus **2100**.

In an exemplary embodiment, as required, the annular body of hardenable fluidic material is then allowed to cure to form a rigid outer annular body about the expanded casing **2155**. In the case where the casing **2155** is slotted, the cured fluidic material preferably permeates and envelops the expanded casing **2155**. The resulting new section of wellbore casing includes the expanded casing **2155** and the rigid outer annular body. The overlapping joint between the pre-existing wellbore casing and the expanded casing **2155** includes the deformed thin wall sections and the compressible outer annular bodies. The inner diameter of the resulting combined wellbore casings is substantially constant. In this manner, a mono-diameter wellbore casing is formed. This process of expanding overlapping tubular members having thin wall end portions with compressible annular bodies into contact can be repeated for the entire length of a wellbore. In this manner, a mono-diameter wellbore casing can be provided for thousands of feet in a subterranean formation.

In an exemplary embodiment, as the expansion cone **2150** nears the upper end of the casing **2155**, the operating flow rate of the second fluidic material is reduced in order to minimize shock to the apparatus **2100**. In an alternative embodiment, the apparatus **2100** includes a shock absorber for absorbing the shock created by the completion of the radial expansion of the casing **2155**.

In an exemplary embodiment, the reduced operating pressure of the second fluidic material ranges from about 100 to 1,000 psi as the expansion cone **2130** nears the end of the casing **2155** in order to optimally provide reduced axial movement and velocity of the expansion cone **2130**. In an exemplary embodiment, the operating pressure of the second fluidic material is reduced during the return stroke of the apparatus **2100** to the range of about 0 to 500 psi in order minimize the resistance to the movement of the expansion cone **2130** during the return stroke. In an exemplary embodiment, the stroke length of the apparatus **2100** ranges from about 10 to 45 feet in order to optimally provide equipment lengths that can be handled by conventional oil well rigging equipment while also minimizing the frequency at which the expansion cone **2130** must be stopped so that the apparatus **2100** can be re-stroked.

In an alternative embodiment, at least a portion of the upper sealing head **2130** includes an expansion cone for radially expanding the casing **2155** during operation of the apparatus **2100** in order to increase the surface area of the casing **2155** acted upon during the radial expansion process. In this manner, the operating pressures can be reduced.

Alternatively, the apparatus **2100** may be used to join a first section of pipeline to an existing section of pipeline. Alternatively, the apparatus **2100** may be used to directly

line the interior of a wellbore with a casing, without the use of an outer annular layer of a hardenable material. Alternatively, the apparatus **2100** may be used to expand a tubular support member in a hole.

Referring now to FIGS. **17**, **17a** and **17b**, another embodiment of an apparatus **2300** for expanding a tubular member will be described. The apparatus **2300** preferably includes a drillpipe **2305**, an innerstring adapter **2310**, a sealing sleeve **2315**, a hydraulic slip body **2320**, hydraulic slips **2325**, an inner sealing mandrel **2330**, an upper sealing head **2335**, a lower sealing head **2340**, a load mandrel **2345**, an outer sealing mandrel **2350**, an expansion cone **2355**, a mechanical slip body **2360**, mechanical slips **2365**, drag blocks **2370**, casing **2375**, fluid passages **2380**, **2385**, **2390**, **2395**, **2400**, **2405**, **2410**, **2415**, and **2485**, and mandrel launcher **2480**.

The drillpipe **2305** is coupled to the innerstring adapter **2310**. During operation of the apparatus **2300**, the drillpipe **2305** supports the apparatus **2300**. The drillpipe **2305** preferably comprises a substantially hollow tubular member or members. The drillpipe **2305** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the drillpipe **2305** is fabricated from coiled tubing in order to facilitate the placement of the apparatus **2300** in non-vertical wellbores. The drillpipe **2305** may be coupled to the innerstring adapter **2310** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. In an exemplary embodiment, the drillpipe **2305** is removably coupled to the innerstring adapter **2310** by a drillpipe connection.

The drillpipe **2305** preferably includes a fluid passage **2380** that is adapted to convey fluidic materials from a surface location into the fluid passage **2385**. In an exemplary embodiment, the fluid passage **2380** is adapted to convey fluidic materials such as, for example, cement, water, epoxy, drilling muds, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 5,000 gallons/minute in order to optimally provide operational efficiency.

The innerstring adapter **2310** is coupled to the drill string **2305** and the sealing sleeve **2315**. The innerstring adapter **2310** preferably comprises a substantially hollow tubular member or members. The innerstring adapter **2310** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the innerstring adapter **2310** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The innerstring adapter **2310** may be coupled to the drill string **2305** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. In an exemplary embodiment, the innerstring adapter **2310** is removably coupled to the drill pipe **2305** by a drillpipe connection. The innerstring adapter **2310** may be coupled to the sealing sleeve **2315** using any number of conventional commercially available mechanical couplings such as, for example, a drillpipe connection, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. In an exemplary embodiment, the innerstring

adapter **2310** is removably coupled to the sealing sleeve **2315** by a standard threaded connection.

The innerstring adapter **2310** preferably includes a fluid passage **2385** that is adapted to convey fluidic materials from the fluid passage **2380** into the fluid passage **2390**. In an exemplary embodiment, the fluid passage **2385** is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud, drilling gases or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The sealing sleeve **2315** is coupled to the innerstring adapter **2310** and the hydraulic slip body **2320**. The sealing sleeve **2315** preferably comprises a substantially hollow tubular member or members. The sealing sleeve **2315** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the sealing sleeve **2315** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low-friction surfaces.

The sealing sleeve **2315** may be coupled to the innerstring adapter **2310** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connections, oilfield country tubular goods specialty threaded connections, or a standard threaded connection. In an exemplary embodiment, the sealing sleeve **2315** is removably coupled to the innerstring adapter **2310** by a standard threaded connection. The sealing sleeve **2315** may be coupled to the hydraulic slip body **2320** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. In an exemplary embodiment, the sealing sleeve **2315** is removably coupled to the hydraulic slip body **2320** by a standard threaded connection.

The sealing sleeve **2315** preferably includes a fluid passage **2390** that is adapted to convey fluidic materials from the fluid passage **2385** into the fluid passage **2395**. In an exemplary embodiment, the fluid passage **2315** is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The hydraulic slip body **2320** is coupled to the sealing sleeve **2315**, the hydraulic slips **2325**, and the inner sealing mandrel **2330**. The hydraulic slip body **2320** preferably comprises a substantially hollow tubular member or members. The hydraulic slip body **2320** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other high strength material. In an exemplary embodiment, the hydraulic slip body **2320** is fabricated from carbon steel in order to optimally provide high strength at low cost.

The hydraulic slip body **2320** may be coupled to the sealing sleeve **2315** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. In an exemplary embodiment, the hydraulic slip body **2320** is removably coupled to the sealing sleeve **2315** by a standard threaded connection. The hydraulic slip body **2320** may be coupled to the slips **2325** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amor-

phous bonding or a standard threaded connection. In an exemplary embodiment, the hydraulic slip body **2320** is removably coupled to the slips **2325** by a standard threaded connection. The hydraulic slip body **2320** may be coupled to the inner sealing mandrel **2330** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding or a standard threaded connection. In an exemplary embodiment, the hydraulic slip body **2320** is removably coupled to the inner sealing mandrel **2330** by a standard threaded connection.

The hydraulic slips body **2320** preferably includes a fluid passage **2395** that is adapted to convey fluidic materials from the fluid passage **2390** into the fluid passage **2405**. In an exemplary embodiment, the fluid passage **2395** is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The hydraulic slips body **2320** preferably includes fluid passage **2400** that are adapted to convey fluidic materials from the fluid passage **2395** into the pressure chambers **2420** of the hydraulic slips **2325**. In this manner, the slips **2325** are activated upon the pressurization of the fluid passage **2395** into contact with the inside surface of the casing **2375**. In an exemplary embodiment, the fluid passages **2400** are adapted to convey fluidic materials such as, for example, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The slips **2325** are coupled to the outside surface of the hydraulic slip body **2320**. During operation of the apparatus **2300**, the slips **2325** are activated upon the pressurization of the fluid passage **2395** into contact with the inside surface of the casing **2375**. In this manner, the slips **2325** maintain the casing **2375** in a substantially stationary position.

The slips **2325** preferably include the fluid passages **2400**, the pressure chambers **2420**, spring bias **2425**, and slip members **2430**. The slips **2325** may comprise any number of conventional commercially available hydraulic slips such as, for example, RTTS packer tungsten carbide hydraulic slips or Model 3L retrievable bridge plug with hydraulic slips. In an exemplary embodiment, the slips **2325** comprise RTTS packer tungsten carbide hydraulic slips available from Halliburton Energy Services in order to optimally provide resistance to axial movement of the casing **2375** during the radial expansion process.

The inner sealing mandrel **2330** is coupled to the hydraulic slip body **2320** and the lower sealing head **2340**. The inner sealing mandrel **2330** preferably comprises a substantially hollow tubular member or members. The inner sealing mandrel **2330** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the inner sealing mandrel **2330** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The inner sealing mandrel **2330** may be coupled to the hydraulic slip body **2320** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In an exemplary embodiment, the inner sealing mandrel **2330** is removably

coupled to the hydraulic slip body **2320** by a standard threaded connection. The inner sealing mandrel **2330** may be coupled to the lower sealing head **2340** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In an exemplary embodiment, the inner sealing mandrel **2330** is removably coupled to the lower sealing head **2340** by a standard threaded connection.

The inner sealing mandrel **2330** preferably includes a fluid passage **2405** that is adapted to convey fluidic materials from the fluid passage **2395** into the fluid passage **2415**. In an exemplary embodiment, the fluid passage **2405** is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The upper sealing head **2335** is coupled to the outer sealing mandrel **2345** and expansion cone **2355**. The upper sealing head **2335** is also movably coupled to the outer surface of the inner sealing mandrel **2330** and the inner surface of the casing **2375**. In this manner, the upper sealing head **2335** reciprocates in the axial direction. The radial clearance between the inner cylindrical surface of the upper sealing head **2335** and the outer surface of the inner sealing mandrel **2330** may range, for example, from about 0.0025 to 0.05 inches. In an exemplary embodiment, the radial clearance between the inner cylindrical surface of the upper sealing head **2335** and the outer surface of the inner sealing mandrel **2330** ranges from about 0.005 to 0.01 inches in order to optimally provide minimal clearance. The radial clearance between the outer cylindrical surface of the upper sealing head **2335** and the inner surface of the casing **2375** may range, for example, from about 0.025 to 0.375 inches. In an exemplary embodiment, the radial clearance between the outer cylindrical surface of the upper sealing head **2335** and the inner surface of the casing **2375** ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone **2355** during the expansion process.

The upper sealing head **2335** preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The upper sealing head **2335** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the upper sealing head **2335** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The inner surface of the upper sealing head **2335** preferably includes one or more annular sealing members **2435** for sealing the interface between the upper sealing head **2335** and the inner sealing mandrel **2330**. The sealing members **2435** may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In an exemplary embodiment, the sealing members **2435** comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

In an exemplary embodiment, the upper sealing head **2335** includes a shoulder **2440** for supporting the upper sealing head on the lower sealing head **1930**.

The upper sealing head **2335** may be coupled to the outer sealing mandrel **2350** using any number of conventional commercially available mechanical couplings such as, for

example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In an exemplary embodiment, the upper sealing head **2335** is removably coupled to the outer sealing mandrel **2350** by a standard threaded connection. In an exemplary embodiment, the mechanical coupling between the upper sealing head **2335** and the outer sealing mandrel **2350** includes one or more sealing members **2445** for fluidically sealing the interface between the upper sealing head **2335** and the outer sealing mandrel **2350**. The sealing members **2445** may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In an exemplary embodiment, the sealing members **2445** comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

The lower sealing head **2340** is coupled to the inner sealing mandrel **2330** and the load mandrel **2345**. The lower sealing head **2340** is also movably coupled to the inner surface of the outer sealing mandrel **2350**. In this manner, the upper sealing head **2335** and outer sealing mandrel **2350** reciprocate in the axial direction. The radial clearance between the outer surface of the lower sealing head **2340** and the inner surface of the outer sealing mandrel **2350** may range, for example, from about 0.0025 to 0.05 inches. In an exemplary embodiment, the radial clearance between the outer surface of the lower sealing head **2340** and the inner surface of the outer sealing mandrel **2350** ranges from about 0.005 to 0.010 inches in order to optimally provide minimal radial clearance.

The lower sealing head **2340** preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The lower sealing head **2340** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield tubular members, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the lower sealing head **2340** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The outer surface of the lower sealing head **2340** preferably includes one or more annular sealing members **2450** for sealing the interface between the lower sealing head **2340** and the outer sealing mandrel **2350**. The sealing members **2450** may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In an exemplary embodiment, the sealing members **2450** comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The lower sealing head **2340** may be coupled to the inner sealing mandrel **2330** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular specialty threaded connection, welding, amorphous bonding, or standard threaded connection. In an exemplary embodiment, the lower sealing head **2340** is removably coupled to the inner sealing mandrel **2330** by a standard threaded connection. In an exemplary embodiment, the mechanical coupling between the lower sealing head **2340** and the inner sealing mandrel **2330** includes one or more sealing members **2455** for fluidically sealing the interface between the lower sealing head **2340** and the inner sealing mandrel **2330**. The sealing members **2455** may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak or metal spring energized seals. In

an exemplary embodiment, the sealing members **2455** comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke length.

The lower sealing head **2340** may be coupled to the load mandrel **2345** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding or a standard threaded connection. In an exemplary embodiment, the lower sealing head **2340** is removably coupled to the load mandrel **2345** by a standard threaded connection. In an exemplary embodiment, the mechanical coupling between the lower sealing head **2340** and the load mandrel **2345** includes one or more sealing members **2460** for fluidically sealing the interface between the lower sealing head **2340** and the load mandrel **2345**. The sealing members **2460** may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In an exemplary embodiment, the sealing members **2460** comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke length.

In an exemplary embodiment, the lower sealing head **2340** includes a throat passage **2465** fluidically coupled between the fluid passages **2405** and **2415**. The throat passage **2465** is preferably of reduced size and is adapted to receive and engage with a plug **2470**, or other similar device. In this manner, the fluid passage **2405** is fluidically isolated from the fluid passage **2415**. In this manner, the pressure chamber **2475** is pressurized.

The outer sealing mandrel **2350** is coupled to the upper sealing head **2335** and the expansion cone **2355**. The outer sealing mandrel **2350** is also movably coupled to the inner surface of the casing **2375** and the outer surface of the lower sealing head **2340**. In this manner, the upper sealing head **2335**, outer sealing mandrel **2350**, and the expansion cone **2355** reciprocate in the axial direction. The radial clearance between the outer surface of the outer sealing mandrel **2350** and the inner surface of the casing **2375** may range, for example, from about 0.025 to 0.375 inches. In an exemplary embodiment, the radial clearance between the outer surface of the outer sealing mandrel **2350** and the inner surface of the casing **2375** ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone **2355** during the expansion process. The radial clearance between the inner surface of the outer sealing mandrel **2350** and the outer surface of the lower sealing head **2340** may range, for example, from about 0.0025 to 0.375 inches. In an exemplary embodiment, the radial clearance between the inner surface of the outer sealing mandrel **2350** and the outer surface of the lower sealing head **2340** ranges from about 0.005 to 0.010 inches in order to optimally provide minimal clearance.

The outer sealing mandrel **2350** preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The outer sealing mandrel **2350** may be fabricated from any number of conventional commercially available materials such as, for example, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the outer sealing mandrel **2350** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The outer sealing mandrel **2350** may be coupled to the upper sealing head **2335** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connections, oilfield country tubular

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goods specialty threaded connections, welding, amorphous bonding, or a standard threaded connection. In an exemplary embodiment, the outer sealing mandrel **2350** is removably coupled to the upper sealing head **2335** by a standard threaded connection. The outer sealing mandrel **2350** may be coupled to the expansion cone **2355** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In an exemplary embodiment, the outer sealing mandrel **2350** is removably coupled to the expansion cone **2355** by a standard threaded connection.

The upper sealing head **2335**, the lower sealing head **2340**, the inner sealing mandrel **2330**, and the outer sealing mandrel **2350** together define a pressure chamber **2475**. The pressure chamber **2475** is fluidically coupled to the passage **2405** via one or more passages **2410**. During operation of the apparatus **2300**, the plug **2470** engages with the throat passage **2465** to fluidically isolate the fluid passage **2415** from the fluid passage **2405**. The pressure chamber **2475** is then pressurized which in turn causes the upper sealing head **2335**, outer sealing mandrel **2350**, and expansion cone **2355** to reciprocate in the axial direction. The axial motion of the expansion cone **2355** in turn expands the casing **2375** in the radial direction.

The load mandrel **2345** is coupled to the lower sealing head **2340** and the mechanical slip body **2360**. The load mandrel **2345** preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The load mandrel **2345** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the load mandrel **2345** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The load mandrel **2345** may be coupled to the lower sealing head **2340** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding or a standard threaded connection. In an exemplary embodiment, the load mandrel **2345** is removably coupled to the lower sealing head **2340** by a standard threaded connection. The load mandrel **2345** may be coupled to the mechanical slip body **2360** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In an exemplary embodiment, the load mandrel **2345** is removably coupled to the mechanical slip body **2360** by a standard threaded connection.

The load mandrel **2345** preferably includes a fluid passage **2415** that is adapted to convey fluidic materials from the fluid passage **2405** to the region outside of the apparatus **2300**. In an exemplary embodiment, the fluid passage **2415** is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The expansion cone **2355** is coupled to the outer sealing mandrel **2350**. The expansion cone **2355** is also movably coupled to the inner surface of the casing **2375**. In this manner, the upper sealing head **2335**, outer sealing mandrel **2350**, and the expansion cone **2355** reciprocate in the axial

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direction. The reciprocation of the expansion cone **2355** causes the casing **2375** to expand in the radial direction.

The expansion cone **2355** preferably comprises an annular member having substantially cylindrical inner and conical outer surfaces. The outside radius of the outside conical surface may range, for example, from about 2 to 34 inches. In an exemplary embodiment, the outside radius of the outside conical surface ranges from about 3 to 28 inches in order to optimally provide radial expansion of the typical casings. The axial length of the expansion cone **2355** may range, for example, from about 2 to 8 times the largest outside diameter of the expansion cone **2355**. In an exemplary embodiment, the axial length of the expansion cone **2355** ranges from about 3 to 5 times the largest outside diameter of the expansion cone **2355** in order to optimally provide stability and centralization of the expansion cone **2355** during the expansion process. In an exemplary embodiment, the angle of attack of the expansion cone **2355** ranges from about 5 to 30 degrees in order to optimally provide frictional forces with radial expansion forces. The optimum angle of attack of the expansion cone **2355** will vary as a function of the operating parameters of the particular expansion operation.

The expansion cone **2355** may be fabricated from any number of conventional commercially available materials such as, for example, machine tool steel, nitride steel, titanium, tungsten carbide, ceramics or other similar high strength materials. In an exemplary embodiment, the expansion cone **2355** is fabricated from D2 machine tool steel in order to optimally provide high strength, abrasion resistance, and galling resistance. In an exemplary embodiment, the outside surface of the expansion cone **2355** has a surface hardness ranging from about 58 to 62 Rockwell C in order to optimally provide high strength, abrasion resistance, resistance to galling.

The expansion cone **2355** may be coupled to the outside sealing mandrel **2350** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In an exemplary embodiment, the expansion cone **2355** is coupled to the outside sealing mandrel **2350** using a standard threaded connection in order to optimally provide high strength and permit the expansion cone **2355** to be easily replaced.

The mandrel launcher **2480** is coupled to the casing **2375**. The mandrel launcher **2480** comprises a tubular section of casing having a reduced wall thickness compared to the casing **2375**. In an exemplary embodiment, the wall thickness of the mandrel launcher **2480** is about 50 to 100% of the wall thickness of the casing **2375**. In this manner, the initiation of the radial expansion of the casing **2375** is facilitated, and the placement of the apparatus **2300** into a wellbore casing and wellbore is facilitated.

The mandrel launcher **2480** may be coupled to the casing **2375** using any number of conventional mechanical couplings. The mandrel launcher **2480** may have a wall thickness ranging, for example, from about 0.15 to 1.5 inches. In an exemplary embodiment, the wall thickness of the mandrel launcher **2480** ranges from about 0.25 to 0.75 inches in order to optimally provide high strength in a minimal profile. The mandrel launcher **2480** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the mandrel launcher **2480** is fabricated from oilfield tubular goods

having a higher strength than that of the casing **2375** but with a smaller wall thickness than the casing **2375** in order to optimally provide a thin walled container having approximately the same burst strength as that of the casing **2375**.

The mechanical slip body **2460** is coupled to the load mandrel **2345**, the mechanical slips **2365**, and the drag blocks **2370**. The mechanical slip body **2460** preferably comprises a tubular member having an inner passage **2485** fluidically coupled to the passage **2415**. In this manner, fluidic materials may be conveyed from the passage **2484** to a region outside of the apparatus **2300**.

The mechanical slip body **2360** may be coupled to the load mandrel **2345** using any number of conventional mechanical couplings. In an exemplary embodiment, the mechanical slip body **2360** is removably coupled to the load mandrel **2345** using threads and sliding steel retaining rings in order to optimally provide a high strength attachment. The mechanical slip body **2360** may be coupled to the mechanical slips **2365** using any number of conventional mechanical couplings. In an exemplary embodiment, the mechanical slip body **2360** is removably coupled to the mechanical slips **2365** using threads and sliding steel retaining rings in order to optimally provide a high strength attachment. The mechanical slip body **2360** may be coupled to the drag blocks **2370** using any number of conventional mechanical couplings. In an exemplary embodiment, the mechanical slip body **2360** is removably coupled to the drag blocks **2365** using threads and sliding steel retaining rings in order to optimally provide a high strength attachment.

The mechanical slips **2365** are coupled to the outside surface of the mechanical slip body **2360**. During operation of the apparatus **2300**, the mechanical slips **2365** prevent upward movement of the casing **2375** and mandrel launcher **2480**. In this manner, during the axial reciprocation of the expansion cone **2355**, the casing **2375** and mandrel launcher **2480** are maintained in a substantially stationary position. In this manner, the mandrel launcher **2480** and casing **2375** are expanded in the radial direction by the axial movement of the expansion cone **2355**.

The mechanical slips **2365** may comprise any number of conventional commercially available mechanical slips such as, for example, RTTS packer tungsten carbide mechanical slips, RTTS packer wicker type mechanical slips or Model 3L retrievable bridge plug tungsten carbide upper mechanical slips. In an exemplary embodiment, the mechanical slips **2365** comprise RTTS packer tungsten carbide mechanical slips available from Halliburton Energy Services in order to optimally provide resistance to axial movement of the casing **2375** during the expansion process.

The drag blocks **2370** are coupled to the outside surface of the mechanical slip body **2360**. During operation of the apparatus **2300**, the drag blocks **2370** prevent upward movement of the casing **2375** and mandrel launcher **2480**. In this manner, during the axial reciprocation of the expansion cone **2355**, the casing **2375** and mandrel launcher **2480** are maintained in a substantially stationary position. In this manner, the mandrel launcher **2480** and casing **2375** are expanded in the radial direction by the axial movement of the expansion cone **2355**.

The drag blocks **2370** may comprise any number of conventional commercially available mechanical slips such as, for example, RTTS packer mechanical drag blocks or Model 3L retrievable bridge plug drag blocks. In an exemplary embodiment, the drag blocks **2370** comprise RTTS packer mechanical drag blocks available from Halliburton

Energy Services in order to optimally provide resistance to axial movement of the casing **2375** during the expansion process.

The casing **2375** is coupled to the mandrel launcher **2480**. The casing **2375** is further removably coupled to the mechanical slips **2365** and drag blocks **2370**. The casing **2375** preferably comprises a tubular member. The casing **2375** may be fabricated from any number of conventional commercially available materials such as, for example, slotted tubulars, oil country tubular goods, carbon steel, low alloy steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the casing **2375** is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills in order to optimally provide high strength. In an exemplary embodiment, the upper end of the casing **2375** includes one or more sealing members positioned about the exterior of the casing **2375**.

During operation, the apparatus **2300** is positioned in a wellbore with the upper end of the casing **2375** positioned in an overlapping relationship within an existing wellbore casing. In order to minimize surge pressures within the borehole during placement of the apparatus **2300**, the fluid passage **2380** is preferably provided with one or more pressure relief passages. During the placement of the apparatus **2300** in the wellbore, the casing **2375** is supported by the expansion cone **2355**.

After positioning of the apparatus **2300** within the bore hole in an overlapping relationship with an existing section of wellbore casing, a first fluidic material is pumped into the fluid passage **2380** from a surface location. The first fluidic material is conveyed from the fluid passage **2380** to the fluid passages **2385**, **2390**, **2395**, **2405**, **2415**, and **2485**. The first fluidic material will then exit the apparatus **2300** and fill the annular region between the outside of the apparatus **2300** and the interior walls of the bore hole.

The first fluidic material may comprise any number of conventional commercially available materials such as, for example, epoxy, drilling mud, slag mix, cement, or water. In an exemplary embodiment, the first fluidic material comprises a hardenable fluidic sealing material such as, for example, slag mix, epoxy, or cement. In this manner, a wellbore casing having an outer annular layer of a hardenable material may be formed.

The first fluidic material may be pumped into the apparatus **2300** at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi, and 0 to 3,000 gallons/minute. In an exemplary embodiment, the first fluidic material is pumped into the apparatus **2300** at operating pressures and flow rates ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to optimally provide operational efficiency.

At a predetermined point in the injection of the first fluidic material such as, for example, after the annular region outside of the apparatus **2300** has been filled to a predetermined level, a plug **2470**, dart, or other similar device is introduced into the first fluidic material. The plug **2470** lodges in the throat passage **2465** thereby fluidically isolating the fluid passage **2405** from the fluid passage **2415**.

After placement of the plug **2470** in the throat passage **2465**, a second fluidic material is pumped into the fluid passage **2380** in order to pressurize the pressure chamber **2475**. The second fluidic material may comprise any number of conventional commercially available materials such as, for example, water, drilling gases, drilling mud or lubricants. In an exemplary embodiment, the second fluidic material

comprises a non-hardenable fluidic material such as, for example, water, drilling mud or lubricant.

The second fluidic material may be pumped into the apparatus **2300** at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 4,500 gallons/minute. In an exemplary embodiment, the second fluidic material is pumped into the apparatus **2300** at operating pressures and flow rates ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to optimally provide operational efficiency.

The pressurization of the pressure chamber **2475** causes the upper sealing head **2335**, outer sealing mandrel **2350**, and expansion cone **2355** to move in an axial direction. The pressurization of the pressure chamber **2475** also causes the hydraulic slips **2325** to expand in the radial direction and hold the casing **2375** in a substantially stationary position. Furthermore, as the expansion cone **2355** moves in the axial direction, the expansion cone **2355** pulls the mandrel launcher **2480** and drag blocks **2370** along, which sets the mechanical slips **2365** and stops further axial movement of the mandrel launcher **2480** and casing **2375**. In this manner, the axial movement of the expansion cone **2355** radially expands the mandrel launcher **2480** and casing **2375**.

Once the upper sealing head **2335**, outer sealing mandrel **2350**, and expansion cone **2355** complete an axial stroke, the operating pressure of the second fluidic material is reduced. The reduction in the operating pressure of the second fluidic material releases the hydraulic slips **2325**. The drill string **2305** is then raised. This causes the inner sealing mandrel **2330**, lower sealing head **2340**, load mandrel **2345**, and mechanical slip body **2360** to move upward. This unsets the mechanical slips **2365** and permits the mechanical slips **2365** and drag blocks **2370** to be moved within the mandrel launcher **2480** and casing **2375**. When the lower sealing head **2340** contacts the upper sealing head **2335**, the second fluidic material is again pressurized and the radial expansion process continues. In this manner, the mandrel launcher **2480** and casing **2375** are radially expanded through repeated axial strokes of the upper sealing head **2335**, outer sealing mandrel **2350** and expansion cone **2355**. Throughout the radial expansion process, the upper end of the casing **2375** is preferably maintained in an overlapping relation with an existing section of wellbore casing.

At the end of the radial expansion process, the upper end of the casing **2375** is expanded into intimate contact with the inside surface of the lower end of the existing wellbore casing. In an exemplary embodiment, the sealing members provided at the upper end of the casing **2375** provide a fluidic seal between the outside surface of the upper end of the casing **2375** and the inside surface of the lower end of the existing wellbore casing. In an exemplary embodiment, the contact pressure between the casing **2375** and the existing section of wellbore casing ranges from about 400 to 10,000 psi in order to optimally provide contact pressure, activate the sealing members, and withstand typical tensile and compressive loading conditions.

In an exemplary embodiment, as the expansion cone **2355** nears the upper end of the casing **2375**, the operating pressure of the second fluidic material is reduced in order to minimize shock to the apparatus **2300**. In an alternative embodiment, the apparatus **2300** includes a shock absorber for absorbing the shock created by the completion of the radial expansion of the casing **2375**.

In an exemplary embodiment, the reduced operating pressure of the second fluidic material ranges from about 100 to 1,000 psi as the expansion cone **2355** nears the end of the casing **2375** in order to optimally provide reduced axial

movement and velocity of the expansion cone **2355**. In an exemplary embodiment, the operating pressure of the second fluidic material is reduced during the return stroke of the apparatus **2300** to the range of about 0 to 500 psi in order to minimize the resistance to the movement of the expansion cone **2355** during the return stroke. In an exemplary embodiment, the stroke length of the apparatus **2300** ranges from about 10 to 45 feet in order to optimally provide equipment that can be handled by typical oil well rigging equipment and minimize the frequency at which the expansion cone **2355** must be stopped to permit the apparatus **2300** to be re-stroked.

In an alternative embodiment, at least a portion of the upper sealing head **2335** includes an expansion cone for radially expanding the mandrel launcher **2480** and casing **2375** during operation of the apparatus **2300** in order to increase the surface area of the casing **2375** acted upon during the radial expansion process. In this manner, the operating pressures can be reduced.

In an alternative embodiment, mechanical slips **2365** are positioned in an axial location between the sealing sleeve **2315** and the inner sealing mandrel **2330** in order to optimally the construction and operation of the apparatus **2300**.

Upon the complete radial expansion of the casing **2375**, if applicable, the first fluidic material is permitted to cure within the annular region between the outside of the expanded casing **2375** and the interior walls of the wellbore. In the case where the casing **2375** is slotted, the cured fluidic material preferably permeates and envelops the expanded casing **2375**. In this manner, a new section of wellbore casing is formed within a wellbore. Alternatively, the apparatus **2300** may be used to join a first section of pipeline to an existing section of pipeline. Alternatively, the apparatus **2300** may be used to directly line the interior of a wellbore with a casing, without the use of an outer annular layer of a hardenable material. Alternatively, the apparatus **2300** may be used to expand a tubular support member in a hole.

During the radial expansion process, the pressurized areas of the apparatus **2300** are limited to the fluid passages **2380**, **2385**, **2390**, **2395**, **2400**, **2405**, and **2410**, and the pressure chamber **2475**. No fluid pressure acts directly on the mandrel launcher **2480** and casing **2375**. This permits the use of operating pressures higher than the mandrel launcher **2480** and casing **2375** could normally withstand.

Referring now to FIG. 18, an exemplary embodiment of an apparatus **2500** for forming a mono-diameter wellbore casing will be described. The apparatus **2500** preferably includes a drillpipe **2505**, an innerstring adapter **2510**, a sealing sleeve **2515**, a hydraulic slip body **2520**, hydraulic slips **2525**, an inner sealing mandrel **2530**, upper sealing head **2535**, lower sealing head **2540**, outer sealing mandrel **2545**, load mandrel **2550**, expansion cone **2555**, casing **2560**, and fluid passages **2565**, **2570**, **2575**, **2580**, **2585**, **2590**, **2595**, and **2600**.

The drillpipe **2505** is coupled to the innerstring adapter **2510**. During operation of the apparatus **2500**, the drillpipe **2505** supports the apparatus **2500**. The drillpipe **2505** preferably comprises a substantially hollow tubular member or members. The drillpipe **2505** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the drillpipe **2505** is fabricated from coiled tubing in order to facilitate the placement of the apparatus **2500** in non-vertical wellbores. The drillpipe **2505** may be coupled to the innerstring adapter **2510** using any number of conventional

commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. In an exemplary embodiment, the drillpipe **2505** is removably coupled to the innerstring adapter **2510** by a drillpipe connection, a drillpipe connection provides the advantages of high strength and easy disassembly.

The drillpipe **2505** preferably includes a fluid passage **2565** that is adapted to convey fluidic materials from a surface location into the fluid passage **2570**. In an exemplary embodiment, the fluid passage **2565** is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The innerstring adapter **2510** is coupled to the drill string **2505** and the sealing sleeve **2515**. The innerstring adapter **2510** preferably comprises a substantially hollow tubular member or members. The innerstring adapter **2510** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the innerstring adapter **2510** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The innerstring adapter **2510** may be coupled to the drill string **2505** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In an exemplary embodiment, the innerstring adapter **2510** is removably coupled to the drill pipe **2505** by a drillpipe connection. The innerstring adapter **2510** may be coupled to the sealing sleeve **2515** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In an exemplary embodiment, the innerstring adapter **2510** is removably coupled to the sealing sleeve **2515** by a standard threaded connection.

The innerstring adapter **2510** preferably includes a fluid passage **2570** that is adapted to convey fluidic materials from the fluid passage **2565** into the fluid passage **2575**. In an exemplary embodiment, the fluid passage **2570** is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The sealing sleeve **2515** is coupled to the innerstring adapter **2510** and the hydraulic slip body **2520**. The sealing sleeve **2515** preferably comprises a substantially hollow tubular member or members. The sealing sleeve **2515** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the sealing sleeve **2515** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low-friction surfaces.

The sealing sleeve **2515** may be coupled to the innerstring adapter **2510** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connections, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In an exem-

plary embodiment, the sealing sleeve **2515** is removably coupled to the innerstring adapter **2510** by a standard threaded connection. The sealing sleeve **2515** may be coupled to the hydraulic slip body **2520** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In an exemplary embodiment, the sealing sleeve **2515** is removably coupled to the hydraulic slip body **2520** by a standard threaded connection.

The sealing sleeve **2515** preferably includes a fluid passage **2575** that is adapted to convey fluidic materials from the fluid passage **2570** into the fluid passage **2580**. In an exemplary embodiment, the fluid passage **2575** is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The hydraulic slip body **2520** is coupled to the sealing sleeve **2515**, the hydraulic slips **2525**, and the inner sealing mandrel **2530**. The hydraulic slip body **2520** preferably comprises a substantially hollow tubular member or members. The hydraulic slip body **2520** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the hydraulic slip body **2520** is fabricated from carbon steel in order to optimally provide high strength.

The hydraulic slip body **2520** may be coupled to the sealing sleeve **2515** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In an exemplary embodiment, the hydraulic slip body **2520** is removably coupled to the sealing sleeve **2515** by a standard threaded connection. The hydraulic slip body **2520** may be coupled to the slips **2525** using any number of conventional commercially available mechanical couplings such as, for example, threaded connection or welding. In an exemplary embodiment, the hydraulic slip body **2520** is removably coupled to the slips **2525** by a threaded connection. The hydraulic slip body **2520** may be coupled to the inner sealing mandrel **2530** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding or a standard threaded connection. In an exemplary embodiment, the hydraulic slip body **2520** is removably coupled to the inner sealing mandrel **2530** by a standard threaded connection.

The hydraulic slips body **2520** preferably includes a fluid passage **2580** that is adapted to convey fluidic materials from the fluid passage **2575** into the fluid passage **2590**. In an exemplary embodiment, the fluid passage **2580** is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The hydraulic slips body **2520** preferably includes fluid passages **2585** that are adapted to convey fluidic materials from the fluid passage **2580** into the pressure chambers of the hydraulic slips **2525**. In this manner, the slips **2525** are activated upon the pressurization of the fluid passage **2580** into contact with the inside surface of the casing **2560**. In an

exemplary embodiment, the fluid passages **2585** are adapted to convey fluidic materials such as, for example, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The slips **2525** are coupled to the outside surface of the hydraulic slip body **2520**. During operation of the apparatus **2500**, the slips **2525** are activated upon the pressurization of the fluid passage **2580** into contact with the inside surface of the casing **2560**. In this manner, the slips **2525** maintain the casing **2560** in a substantially stationary position.

The slips **2525** preferably include the fluid passages **2585**, the pressure chambers **2605**, spring bias **2610**, and slip members **2615**. The slips **2525** may comprise any number of conventional commercially available hydraulic slips such as, for example, RTTS packer tungsten carbide hydraulic slips or Model 3L retrievable bridge plug with hydraulic slips. In an exemplary embodiment, the slips **2525** comprise RTTS packer tungsten carbide hydraulic slips available from Halliburton Energy Services in order to optimally provide resistance to axial movement of the casing **2560** during the expansion process.

The inner sealing mandrel **2530** is coupled to the hydraulic slip body **2520** and the lower sealing head **2540**. The inner sealing mandrel **2530** preferably comprises a substantially hollow tubular member or members. The inner sealing mandrel **2530** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the inner sealing mandrel **2530** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The inner sealing mandrel **2530** may be coupled to the hydraulic slip body **2520** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding, or a standard threaded connection. In an exemplary embodiment, the inner sealing mandrel **2530** is removably coupled to the hydraulic slip body **2520** by a standard threaded connection. The inner sealing mandrel **2530** may be coupled to the lower sealing head **2540** using any number of conventional commercially available mechanical couplings such as, for example, oilfield country tubular goods specialty type threaded connection, drillpipe connection, welding, amorphous bonding, or a standard threaded connection. In an exemplary embodiment, the inner sealing mandrel **2530** is removably coupled to the lower sealing head **2540** by a standard threaded connection.

The inner sealing mandrel **2530** preferably includes a fluid passage **2590** that is adapted to convey fluidic materials from the fluid passage **2580** into the fluid passage **2600**. In an exemplary embodiment, the fluid passage **2590** is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The upper sealing head **2535** is coupled to the outer sealing mandrel **2545** and expansion cone **2555**. The upper sealing head **2535** is also movably coupled to the outer surface of the inner sealing mandrel **2530** and the inner surface of the casing **2560**. In this manner, the upper sealing head **2535** reciprocates in the axial direction. The radial clearance between the inner cylindrical surface of the upper sealing head **2535** and the outer surface of the inner sealing

mandrel **2530** may range, for example, from about 0.0025 to 0.05 inches. In an exemplary embodiment, the radial clearance between the inner cylindrical surface of the upper sealing head **2535** and the outer surface of the inner sealing mandrel **2530** ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance. The radial clearance between the outer cylindrical surface of the upper sealing head **2535** and the inner surface of the casing **2560** may range, for example, from about 0.025 to 0.375 inches. In an exemplary embodiment, the radial clearance between the outer cylindrical surface of the upper sealing head **2535** and the inner surface of the casing **2560** ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone **2535** during the expansion process.

The upper sealing head **2535** preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The upper sealing head **2535** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the upper sealing head **2535** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The inner surface of the upper sealing head **2535** preferably includes one or more annular sealing members **2620** for sealing the interface between the upper sealing head **2535** and the inner sealing mandrel **2530**. The sealing members **2620** may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In an exemplary embodiment, the sealing members **2620** comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

In an exemplary embodiment, the upper sealing head **2535** includes a shoulder **2625** for supporting the upper sealing head **2535**, outer sealing mandrel **2545**, and expansion cone **2555** on the lower sealing head **2540**.

The upper sealing head **2535** may be coupled to the outer sealing mandrel **2545** using any number of conventional commercially available mechanical couplings such as, for example, oilfield country tubular goods specialty threaded connection, pipeline connection, welding, amorphous bonding, or a standard threaded connection. In an exemplary embodiment, the upper sealing head **2535** is removably coupled to the outer sealing mandrel **2545** by a standard threaded connection. In an exemplary embodiment, the mechanical coupling between the upper sealing head **2535** and the outer sealing mandrel **2545** includes one or more sealing members **2630** for fluidically sealing the interface between the upper sealing head **2535** and the outer sealing mandrel **2545**. The sealing members **2630** may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In an exemplary embodiment, the sealing members **2630** comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The lower sealing head **2540** is coupled to the inner sealing mandrel **2530** and the load mandrel **2550**. The lower sealing head **2540** is also movably coupled to the inner surface of the outer sealing mandrel **2545**. In this manner, the upper sealing head **2535**, outer sealing mandrel **2545**, and expansion cone **2555** reciprocate in the axial direction.

The radial clearance between the outer surface of the lower sealing head **2540** and the inner surface of the outer

sealing mandrel **2545** may range, for example, from about 0.0025 to 0.05 inches. In an exemplary embodiment, the radial clearance between the outer surface of the lower sealing head **2540** and the inner surface of the outer sealing mandrel **2545** ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The lower sealing head **2540** preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The lower sealing head **2540** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the lower sealing head **2540** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The outer surface of the lower sealing head **2540** preferably includes one or more annular sealing members **2635** for sealing the interface between the lower sealing head **2540** and the outer sealing mandrel **2545**. The sealing members **2635** may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In an exemplary embodiment, the sealing members **2635** comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The lower sealing head **2540** may be coupled to the inner sealing mandrel **2530** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connections, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. In an exemplary embodiment, the lower sealing head **2540** is removably coupled to the inner sealing mandrel **2530** by a standard threaded connection. In an exemplary embodiment, the mechanical coupling between the lower sealing head **2540** and the inner sealing mandrel **2530** includes one or more sealing members **2640** for fluidically sealing the interface between the lower sealing head **2540** and the inner sealing mandrel **2530**. The sealing members **2640** may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In an exemplary embodiment, the sealing members **2640** comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The lower sealing head **2540** may be coupled to the load mandrel **2550** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding or a standard threaded connection. In an exemplary embodiment, the lower sealing head **2540** is removably coupled to the load mandrel **2550** by a standard threaded connection. In an exemplary embodiment, the mechanical coupling between the lower sealing head **2540** and the load mandrel **2550** includes one or more sealing members **2645** for fluidically sealing the interface between the lower sealing head **2540** and the load mandrel **2550**. The sealing members **2645** may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In an exemplary embodiment, the sealing members **2645** comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

In an exemplary embodiment, the lower sealing head **2540** includes a throat passage **2650** fluidically coupled between the fluid passages **2590** and **2600**. The throat

passage **2650** is preferably of reduced size and is adapted to receive and engage with a plug **2655**, or other similar device. In this manner, the fluid passage **2590** is fluidically isolated from the fluid passage **2600**. In this manner, the pressure chamber **2660** is pressurized.

The outer sealing mandrel **2545** is coupled to the upper sealing head **2535** and the expansion cone **2555**. The outer sealing mandrel **2545** is also movably coupled to the inner surface of the casing **2560** and the outer surface of the lower sealing head **2540**. In this manner, the upper sealing head **2535**, outer sealing mandrel **2545**, and the expansion cone **2555** reciprocate in the axial direction. The radial clearance between the outer surface of the outer sealing mandrel **2545** and the inner surface of the casing **2560** may range, for example, from about 0.025 to 0.375 inches. In an exemplary embodiment, the radial clearance between the outer surface of the outer sealing mandrel **2545** and the inner surface of the casing **2560** ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone **2535** during the expansion process. The radial clearance between the inner surface of the outer sealing mandrel **2545** and the outer surface of the lower sealing head **2540** may range, for example, from about 0.005 to 0.01 inches. In an exemplary embodiment, the radial clearance between the inner surface of the outer sealing mandrel **2545** and the outer surface of the lower sealing head **2540** ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The outer sealing mandrel **2545** preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The outer sealing mandrel **2545** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the outer sealing mandrel **2545** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The outer sealing mandrel **2545** may be coupled to the upper sealing head **2535** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding, or a standard threaded connection. In an exemplary embodiment, the outer sealing mandrel **2545** is removably coupled to the upper sealing head **2535** by a standard threaded connection. The outer sealing mandrel **2545** may be coupled to the expansion cone **2555** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding, or a standard threaded connection. In an exemplary embodiment, the outer sealing mandrel **2545** is removably coupled to the expansion cone **2555** by a standard threaded connection.

The upper sealing head **2535**, the lower sealing head **2540**, the inner sealing mandrel **2530**, and the outer sealing mandrel **2545** together define a pressure chamber **2660**. The pressure chamber **2660** is fluidically coupled to the passage **2590** via one or more passages **2595**. During operation of the apparatus **2500**, the plug **2655** engages with the throat passage **2650** to fluidically isolate the fluid passage **2590** from the fluid passage **2600**. The pressure chamber **2660** is then pressurized which in turn causes the upper sealing head **2535**, outer sealing mandrel **2545**, and expansion cone **2555**

to reciprocate in the axial direction. The axial motion of the expansion cone **2555** in turn expands the casing **2560** in the radial direction.

The load mandrel **2550** is coupled to the lower sealing head **2540**. The load mandrel **2550** preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The load mandrel **2550** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the load mandrel **2550** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The load mandrel **2550** may be coupled to the lower sealing head **2540** using any number of conventional commercially available mechanical couplings such as, for example, oilfield country tubular goods, drillpipe connection, welding, amorphous bonding, or a standard threaded connection. In an exemplary embodiment, the load mandrel **2550** is removably coupled to the lower sealing head **2540** by a standard threaded connection.

The load mandrel **2550** preferably includes a fluid passage **2600** that is adapted to convey fluidic materials from the fluid passage **2590** to the region outside of the apparatus **2500**. In an exemplary embodiment, the fluid passage **2600** is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud, or lubricants at operating pressures and flow rates ranging, for example, from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The expansion cone **2555** is coupled to the outer sealing mandrel **2545**. The expansion cone **2555** is also movably coupled to the inner surface of the casing **2560**. In this manner, the upper sealing head **2535**, outer sealing mandrel **2545**, and the expansion cone **2555** reciprocate in the axial direction. The reciprocation of the expansion cone **2555** causes the casing **2560** to expand in the radial direction.

The expansion cone **2555** preferably comprises an annular member having substantially cylindrical inner and conical outer surfaces. The outside radius of the outside conical surface may range, for example, from about 2 to 34 inches. In an exemplary embodiment, the outside radius of the outside conical surface ranges from about 3 to 28 in order to optimally provide radial expansion for the widest variety of tubular casings. The axial length of the expansion cone **2555** may range, for example, from about 2 to 8 times the largest outside diameter of the expansion cone **2535**. In an exemplary embodiment, the axial length of the expansion cone **2535** ranges from about 3 to 5 times the largest outside diameter of the expansion cone **2535** in order to optimally provide stabilization and centralization of the expansion cone **2535** during the expansion process. In an exemplary embodiment, the maximum outside diameter of the expansion cone **2555** is between about 95 to 99% of the inside diameter of the existing wellbore that the casing **2560** will be joined with. In an exemplary embodiment, the angle of attack of the expansion cone **2555** ranges from about 5 to 30 degrees in order to optimally balance frictional forces and radial expansion forces. The optimum angle of attack of the expansion cone **2535** will vary as a function of the particular operational features of the expansion operation.

The expansion cone **2555** may be fabricated from any number of conventional commercially available materials such as, for example, machine tool steel, nitride steel, titanium, tungsten carbide, ceramics or other similar high strength materials. In an exemplary embodiment, the expansion cone **2555** is fabricated from D2 machine tool steel in

order to optimally provide high strength, and resistance to wear and galling. In an exemplary embodiment, the outside surface of the expansion cone **2555** has a surface hardness ranging from about 58 to 62 Rockwell C in order to optimally provide high strength and wear resistance.

The expansion cone **2555** may be coupled to the outside sealing mandrel **2545** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding or a standard threaded connection. In an exemplary embodiment, the expansion cone **2555** is coupled to the outside sealing mandrel **2545** using a standard threaded connection in order to optimally provide high strength and easy replacement of the expansion cone **2555**.

The casing **2560** is removably coupled to the slips **2525** and expansion cone **2555**. The casing **2560** preferably comprises a tubular member. The casing **2560** may be fabricated from any number of conventional commercially available materials such as, for example, slotted tubulars, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the casing **2560** is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills in order to optimally provide high strength using standardized materials.

In an exemplary embodiment, the upper end **2665** of the casing **2560** includes a thin wall section **2670** and an outer annular sealing member **2675**. In an exemplary embodiment, the wall thickness of the thin wall section **2670** is about 50 to 100% of the regular wall thickness of the casing **2560**. In this manner, the upper end **2665** of the casing **2560** may be easily radially expanded and deformed into intimate contact with the lower end of an existing section of wellbore casing. In an exemplary embodiment, the lower end of the existing section of casing also includes a thin wall section. In this manner, the radial expansion of the thin walled section **2670** of casing **2560** into the thin walled section of the existing wellbore casing results in a wellbore casing having a substantially constant inside diameter.

The annular sealing member **2675** may be fabricated from any number of conventional commercially available sealing materials such as, for example, epoxy, rubber, metal, or plastic. In an exemplary embodiment, the annular sealing member **2675** is fabricated from StrataLock epoxy in order to optimally provide compressibility and resistance to wear. The outside diameter of the annular sealing member **2675** preferably ranges from about 70 to 95% of the inside diameter of the lower section of the wellbore casing that the casing **2560** is joined to. In this manner, after radial expansion, the annular sealing member **2670** optimally provides a fluidic seal and also preferably optimally provides sufficient frictional force with the inside surface of the existing section of wellbore casing during the radial expansion of the casing **2560** to support the casing **2560**.

In an exemplary embodiment, the lower end **2680** of the casing **2560** includes a thin wall section **2685** and an outer annular sealing member **2690**. In an exemplary embodiment, the wall thickness of the thin wall section **2685** is about 50 to 100% of the regular wall thickness of the casing **2560**. In this manner, the lower end **2680** of the casing **2560** may be easily expanded and deformed. Furthermore, in this manner, another section of casing may be easily joined with the lower end **2680** of the casing **2560** using a radial expansion process. In an exemplary embodiment, the upper end of the other section of casing also includes a thin wall section. In this manner, the radial expansion of the thin walled section

of the upper end of the other casing into the thin walled section **2685** of the lower end **2680** of the casing **2560** results in a wellbore casing having a substantially constant inside diameter.

The annular sealing member **2690** may be fabricated from any number of conventional commercially available sealing materials such as, for example, rubber, metal, plastic or epoxy. In an exemplary embodiment, the annular sealing member **2690** is fabricated from StrataLock epoxy in order to optimally provide compressibility and resistance to wear. The outside diameter of the annular sealing member **2690** preferably ranges from about 70 to 95% of the inside diameter of the lower section of the existing wellbore casing that the casing **2560** is joined to. In this manner, after radial expansion, the annular sealing member **2690** preferably provides a fluidic seal and also preferably provides sufficient frictional force with the inside wall of the wellbore during the radial expansion of the casing **2560** to support the casing **2560**.

During operation, the apparatus **2500** is preferably positioned in a wellbore with the upper end **2665** of the casing **2560** positioned in an overlapping relationship with the lower end of an existing wellbore casing. In an exemplary embodiment, the thin wall section **2670** of the casing **2560** is positioned in opposing overlapping relation with the thin wall section and outer annular sealing member of the lower end of the existing section of wellbore casing. In this manner, the radial expansion of the casing **2560** will compress the thin wall sections and annular compressible members of the upper end **2665** of the casing **2560** and the lower end of the existing wellbore casing into intimate contact. During the positioning of the apparatus **2500** in the wellbore, the casing **2560** is supported by the expansion cone **2555**.

After positioning of the apparatus **2500**, a first fluidic material is then pumped into the fluid passage **2565**. The first fluidic material may comprise any number of conventional commercially available materials such as, for example, cement, water, slag-mix, epoxy or drilling mud. In an exemplary embodiment, the first fluidic material comprises a hardenable fluidic sealing material such as, for example, cement, epoxy, or slag-mix in order to optimally provide a hardenable outer annular body around the expanded casing **2560**.

The first fluidic material may be pumped into the fluid passage **2565** at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 3,000 gallons/minute. In an exemplary embodiment, the first fluidic material is pumped into the fluid passage **2565** at operating pressures and flow rates ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to optimally provide operational efficiency.

The first fluidic material pumped into the fluid passage **2565** passes through the fluid passages **2570**, **2575**, **2580**, **2590**, **2600** and then outside of the apparatus **2500**. The first fluidic material then preferably fills the annular region between the outside of the apparatus **2500** and the interior walls of the wellbore.

The plug **2655** is then introduced into the fluid passage **2565**. The plug **2655** lodges in the throat passage **2650** and fluidically isolates and blocks off the fluid passage **2590**. In an exemplary embodiment, a couple of volumes of a non-hardenable fluidic material are then pumped into the fluid passage **2565** in order to remove any hardenable fluidic material contained within and to ensure that none of the fluid passages are blocked.

A second fluidic material is then pumped into the fluid passage **2565**. The second fluidic material may comprise any

number of conventional commercially available materials such as, for example, water, drilling gases, drilling mud or lubricant. In an exemplary embodiment, the second fluidic material comprises a non-hardenable fluidic material such as, for example, water, drilling mud, or lubricant in order to optimally provide pressurization of the pressure chamber **2660** and minimize friction.

The second fluidic material may be pumped into the fluid passage **2565** at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 4,500 gallons/minute. In an exemplary embodiment, the second fluidic material is pumped into the fluid passage **2565** at operating pressures and flow rates ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to optimally provide operational efficiency.

The second fluidic material pumped into the fluid passage **2565** passes through the fluid passages **2570**, **2575**, **2580**, **2590** and into the pressure chambers **2605** of the slips **2525**, and into the pressure chamber **2660**. Continued pumping of the second fluidic material pressurizes the pressure chambers **2605** and **2660**.

The pressurization of the pressure chambers **2605** causes the slip members **2525** to expand in the radial direction and grip the interior surface of the casing **2560**. The casing **2560** is then preferably maintained in a substantially stationary position.

The pressurization of the pressure chamber **2660** causes the upper sealing head **2535**, outer sealing mandrel **2545** and expansion cone **2555** to move in an axial direction relative to the casing **2560**. In this manner, the expansion cone **2555** will cause the casing **2560** to expand in the radial direction, beginning with the lower end **2685** of the casing **2560**.

During the radial expansion process, the casing **2560** is prevented from moving in an upward direction by the slips **2525**. A length of the casing **2560** is then expanded in the radial direction through the pressurization of the pressure chamber **2660**. The length of the casing **2560** that is expanded during the expansion process will be proportional to the stroke length of the upper sealing head **2535**, outer sealing mandrel **2545**, and expansion cone **2555**.

Upon the completion of a stroke, the operating pressure of the second fluidic material is reduced and the upper sealing head **2535**, outer sealing mandrel **2545**, and expansion cone **2555** drop to their rest positions with the casing **2560** supported by the expansion cone **2555**. The position of the drillpipe **2505** is preferably adjusted throughout the radial expansion process in order to maintain the overlapping relationship between the thin walled sections of the lower end of the existing wellbore casing and the upper end of the casing **2560**. In an exemplary embodiment, the stroking of the expansion cone **2555** is then repeated, as necessary, until the thin walled section **2670** of the upper end **2665** of the casing **2560** is expanded into the thin walled section of the lower end of the existing wellbore casing. In this manner, a wellbore casing is formed including two adjacent sections of casing having a substantially constant inside diameter. This process may then be repeated for the entirety of the wellbore to provide a wellbore casing thousands of feet in length having a substantially constant inside diameter.

In an exemplary embodiment, during the final stroke of the expansion cone **2555**, the slips **2525** are positioned as close as possible to the thin walled section **2670** of the upper end **2665** of the casing **2560** in order minimize slippage between the casing **2560** and the existing wellbore casing at the end of the radial expansion process. Alternatively, or in addition, the outside diameter of the annular sealing member **2675** is selected to ensure sufficient interference fit with the

inside diameter of the lower end of the existing casing to prevent axial displacement of the casing **2560** during the final stroke. Alternatively, or in addition, the outside diameter of the annular sealing member **2690** is selected to provide an interference fit with the inside walls of the wellbore at an earlier point in the radial expansion process so as to prevent further axial displacement of the casing **2560**. In this final alternative, the interference fit is preferably selected to permit expansion of the casing **2560** by pulling the expansion cone **2555** out of the wellbore, without having to pressurize the pressure chamber **2660**.

During the radial expansion process, the pressurized areas of the apparatus **2500** are preferably limited to the fluid passages **2565**, **2570**, **2575**, **2580**, and **2590**, the pressure chambers **2605** within the slips **2525**, and the pressure chamber **2660**. No fluid pressure acts directly on the casing **2560**. This permits the use of operating pressures higher than the casing **2560** could normally withstand.

Once the casing **2560** has been completely expanded off of the expansion cone **2555**, the remaining portions of the apparatus **2500** are removed from the wellbore. In an exemplary embodiment, the contact pressure between the deformed thin wall sections and compressible annular members of the lower end of the existing casing and the upper end **2665** of the casing **2560** ranges from about 400 to 10,000 psi in order to optimally support the casing **2560** using the existing wellbore casing.

In this manner, the casing **2560** is radially expanded into contact with an existing section of casing by pressurizing the interior fluid passages **2565**, **2570**, **2575**, **2580**, and **2590**, the pressure chambers of the slips **2605** and the pressure chamber **2660** of the apparatus **2500**.

In an exemplary embodiment, as required, the annular body of hardenable fluidic material is then allowed to cure to form a rigid outer annular body about the expanded casing **2560**. In the case where the casing **2560** is slotted, the cured fluidic material preferably permeates and envelops the expanded casing **2560**. The resulting new section of wellbore casing includes the expanded casing **2560** and the rigid outer annular body. The overlapping joint between the pre-existing wellbore casing and the expanded casing **2560** includes the deformed thin wall sections and the compressible outer annular bodies. The inner diameter of the resulting combined wellbore casings is substantially constant. In this manner, a mono-diameter wellbore casing is formed. This process of expanding overlapping tubular members having thin wall end portions with compressible annular bodies into contact can be repeated for the entire length of a wellbore. In this manner, a mono-diameter wellbore casing can be provided for thousands of feet in a subterranean formation.

In an exemplary embodiment, as the expansion cone **2555** nears the upper end **2665** of the casing **2560**, the operating pressure of the second fluidic material is reduced in order to minimize shock to the apparatus **2500**. In an alternative embodiment, the apparatus **2500** includes a shock absorber for absorbing the shock created by the completion of the radial expansion of the casing **2560**.

In an exemplary embodiment, the reduced operating pressure of the second fluidic material ranges from about 100 to 1,000 psi as the expansion cone **2555** nears the end of the casing **2560** in order to optimally provide reduced axial movement and velocity of the expansion cone **2555**. In an exemplary embodiment, the operating pressure of the second fluidic material is reduced during the return stroke of the apparatus **2500** to the range of about 0 to 500 psi in order to minimize the resistance to the movement of the expansion cone **2555** during the return stroke. In an exemplary embodi-

ment, the stroke length of the apparatus **2500** ranges from about 10 to 45 feet in order to optimally provide equipments lengths that can be easily handled using typical oil well rigging equipment and also minimize the frequency at which apparatus **2500** must be re-stroked.

In an alternative embodiment, at least a portion of the upper sealing head **2535** includes an expansion cone for radially expanding the casing **2560** during operation of the apparatus **2500** in order to increase the surface area of the casing **2560** acted upon during the radial expansion process. In this manner, the operating pressures can be reduced.

Alternatively, the apparatus **2500** may be used to join a first section of pipeline to an existing section of pipeline. Alternatively, the apparatus **2500** may be used to directly line the interior of a wellbore with a casing, without the use of an outer annular layer of a hardenable material. Alternatively, the apparatus **2500** may be used to expand a tubular support member in a hole.

Referring now to FIGS. **19**, **19a** and **19b**, another embodiment of an apparatus **2700** for expanding a tubular member will be described. The apparatus **2700** preferably includes a drillpipe **2705**, an innerstring adapter **2710**, a sealing sleeve **2715**, a first inner sealing mandrel **2720**, a first upper sealing head **2725**, a first lower sealing head **2730**, a first outer sealing mandrel **2735**, a second inner sealing mandrel **2740**, a second upper sealing head **2745**, a second lower sealing head **2750**, a second outer sealing mandrel **2755**, a load mandrel **2760**, an expansion cone **2765**, a mandrel launcher **2770**, a mechanical slip body **2775**, mechanical slips **2780**, drag blocks **2785**, casing **2790**, and fluid passages **2795**, **2800**, **2805**, **2810**, **2815**, **2820**, **2825**, and **2830**.

The drillpipe **2705** is coupled to the innerstring adapter **2710**. During operation of the apparatus **2700**, the drillpipe **2705** supports the apparatus **2700**. The drillpipe **2705** preferably comprises a substantially hollow tubular member or members. The drillpipe **2705** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel, or other similar high strength materials. In an exemplary embodiment, the drillpipe **2705** is fabricated from coiled tubing in order to facilitate the placement of the apparatus **2700** in non-vertical wellbores. The drillpipe **2705** may be coupled to the innerstring adapter **2710** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. In an exemplary embodiment, the drillpipe **2705** is removably coupled to the innerstring adapter **2710** by a drillpipe connection in order to optimally provide high strength and easy disassembly.

The drillpipe **2705** preferably includes a fluid passage **2795** that is adapted to convey fluidic materials from a surface location into the fluid passage **2800**. In an exemplary embodiment, the fluid passage **2795** is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The innerstring adapter **2710** is coupled to the drill string **2705** and the sealing sleeve **2715**. The innerstring adapter **2710** preferably comprises a substantially hollow tubular member or members. The innerstring adapter **2710** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary

embodiment, the innerstring adapter **2710** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The innerstring adapter **2710** may be coupled to the drill string **2705** using any number of conventional commercially available mechanical couplings such as, for example, drill-pipe connection, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. In an exemplary embodiment, the innerstring adapter **2710** is removably coupled to the drill pipe **2705** by a standard threaded connection in order to optimally provide high strength and easy disassembly. The innerstring adapter **2710** may be coupled to the sealing sleeve **2715** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In an exemplary embodiment, the innerstring adapter **2710** is removably coupled to the sealing sleeve **2715** by a standard threaded connection.

The innerstring adapter **2710** preferably includes a fluid passage **2800** that is adapted to convey fluidic materials from the fluid passage **2795** into the fluid passage **2805**. In an exemplary embodiment, the fluid passage **2800** is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The sealing sleeve **2715** is coupled to the innerstring adapter **2710** and the first inner sealing mandrel **2720**. The sealing sleeve **2715** preferably comprises a substantially hollow tubular member or members. The sealing sleeve **2715** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the sealing sleeve **2715** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The sealing sleeve **2715** may be coupled to the innerstring adapter **2710** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding, or a standard threaded connection. In an exemplary embodiment, the sealing sleeve **2715** is removably coupled to the innerstring adapter **2710** by a standard threaded connector. The sealing sleeve **2715** may be coupled to the first inner sealing mandrel **2720** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding or a standard threaded connection. In an exemplary embodiment, the sealing sleeve **2715** is removably coupled to the inner sealing mandrel **2720** by a standard threaded connection.

The sealing sleeve **2715** preferably includes a fluid passage **2802** that is adapted to convey fluidic materials from the fluid passage **2800** into the fluid passage **2805**. In an exemplary embodiment, the fluid passage **2802** is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The first inner sealing mandrel **2720** is coupled to the sealing sleeve **2715** and the first lower sealing head **2730**. The first inner sealing mandrel **2720** preferably comprises a

substantially hollow tubular member or members. The first inner sealing mandrel **2720** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the first inner sealing mandrel **2720** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The first inner sealing mandrel **2720** may be coupled to the sealing sleeve **2715** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In an exemplary embodiment, the first inner sealing mandrel **2720** is removably coupled to the sealing sleeve **2715** by a standard threaded connection. The first inner sealing mandrel **2720** may be coupled to the first lower sealing head **2730** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding, or a standard threaded connection. In an exemplary embodiment, the first inner sealing mandrel **2720** is removably coupled to the first lower sealing head **2730** by a standard threaded connection.

The first inner sealing mandrel **2720** preferably includes a fluid passage **2805** that is adapted to convey fluidic materials from the fluid passage **2802** into the fluid passage **2810**. In an exemplary embodiment, the fluid passage **2805** is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The first upper sealing head **2725** is coupled to the first outer sealing mandrel **2735**, the second upper sealing head **2745**, the second outer sealing mandrel **2755**, and the expansion cone **2765**. The first upper sealing head **2725** is also movably coupled to the outer surface of the first inner sealing mandrel **2720** and the inner surface of the casing **2790**. In this manner, the first upper sealing head **2725** reciprocates in the axial direction. The radial clearance between the inner cylindrical surface of the first upper sealing head **2725** and the outer surface of the first inner sealing mandrel **2720** may range, for example, from about 0.0025 to 0.05 inches. In an exemplary embodiment, the radial clearance between the inner cylindrical surface of the first upper sealing head **2725** and the outer surface of the first inner sealing mandrel **2720** ranges from about 0.005 to 0.125 inches in order to optimally provide minimal radial clearance. The radial clearance between the outer cylindrical surface of the first upper sealing head **2725** and the inner surface of the casing **2790** may range, for example, from about 0.025 to 0.375 inches. In an exemplary embodiment, the radial clearance between the outer cylindrical surface of the first upper sealing head **2725** and the inner surface of the casing **2790** ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone **2765** during the expansion process.

The first upper sealing head **2725** preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The first upper sealing head **2725** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary

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embodiment, the first upper sealing head 2725 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance and low friction surfaces. The inner surface of the first upper sealing head 2725 preferably includes one or more annular sealing members 2835 for sealing the interface between the first upper sealing head 2725 and the first inner sealing mandrel 2720. The sealing members 2835 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In an exemplary embodiment, the sealing members 2835 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

In an exemplary embodiment, the first upper sealing head 2725 includes a shoulder 2840 for supporting the first upper sealing head 2725 on the first lower sealing head 2730.

The first upper sealing head 2725 may be coupled to the first outer sealing mandrel 2735 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding or a standard threaded connection. In an exemplary embodiment, the first upper sealing head 2725 is removably coupled to the first outer sealing mandrel 2735 by a standard threaded connection. In an exemplary embodiment, the mechanical coupling between the first upper sealing head 2725 and the first outer sealing mandrel 2735 includes one or more sealing members 2845 for fluidically sealing the interface between the first upper sealing head 2725 and the first outer sealing mandrel 2735. The sealing members 2845 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In an exemplary embodiment, the sealing members 2845 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

The first lower sealing head 2730 is coupled to the first inner sealing mandrel 2720 and the second inner sealing mandrel 2740. The first lower sealing head 2730 is also movably coupled to the inner surface of the first outer sealing mandrel 2735. In this manner, the first upper sealing head 2725 and first outer sealing mandrel 2735 reciprocate in the axial direction. The radial clearance between the outer surface of the first lower sealing head 2730 and the inner surface of the first outer sealing mandrel 2735 may range, for example, from about 0.0025 to 0.05 inches. In an exemplary embodiment, the radial clearance between the outer surface of the first lower sealing head 2730 and the inner surface of the first outer sealing mandrel 2735 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The first lower sealing head 2730 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The first lower sealing head 2730 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the first lower sealing head 2730 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The outer surface of the first lower sealing head 2730 preferably includes one or more annular sealing members 2850 for sealing the interface between the first lower sealing head 2730 and the first outer sealing mandrel 2735. The sealing members 2850 may comprise any number of conventional

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commercially available annular sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In an exemplary embodiment, the sealing members 2850 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

The first lower sealing head 2730 may be coupled to the first inner sealing mandrel 2720 using any number of conventional commercially available mechanical couplings such as, for example, oilfield country tubular goods specialty threaded connections, welding, amorphous bonding, or standard threaded connection. In an exemplary embodiment, the first lower sealing head 2730 is removably coupled to the first inner sealing mandrel 2720 by a standard threaded connection. In an exemplary embodiment, the mechanical coupling between the first lower sealing head 2730 and the first inner sealing mandrel 2720 includes one or more sealing members 2855 for fluidically sealing the interface between the first lower sealing head 2730 and the first inner sealing mandrel 2720. The sealing members 2855 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In an exemplary embodiment, the sealing members 2855 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

The first lower sealing head 2730 may be coupled to the second inner sealing mandrel 2740 using any number of conventional commercially available mechanical couplings such as, for example, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In an exemplary embodiment, the lower sealing head 2730 is removably coupled to the second inner sealing mandrel 2740 by a standard threaded connection. In an exemplary embodiment, the mechanical coupling between the first lower sealing head 2730 and the second inner sealing mandrel 2740 includes one or more sealing members 2860 for fluidically sealing the interface between the first lower sealing head 2730 and the second inner sealing mandrel 2740. The sealing members 2860 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In an exemplary embodiment, the sealing members 2860 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

The first outer sealing mandrel 2735 is coupled to the first upper sealing head 2725, the second upper sealing head 2745, the second outer sealing mandrel 2755, and the expansion cone 2765. The first outer sealing mandrel 2735 is also movably coupled to the inner surface of the casing 2790 and the outer surface of the first lower sealing head 2730. In this manner, the first upper sealing head 2725, first outer sealing mandrel 2735, second upper sealing head 2745, second outer sealing mandrel 2755, and the expansion cone 2765 reciprocate in the axial direction. The radial clearance between the outer surface of the first outer sealing mandrel 2735 and the inner surface of the casing 2790 may range, for example, from about 0.025 to 0.375 inches. In an exemplary embodiment, the radial clearance between the outer surface of the first outer sealing mandrel 2735 and the inner surface of the casing 2790 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 2765 during the expansion process. The radial clearance between the inner surface of the first outer sealing mandrel 2735 and the outer surface of the first lower sealing head 2730 may range, for example, from about

0.0025 to 0.05 inches. In an exemplary embodiment, the radial clearance between the inner surface of the first outer sealing mandrel **2735** and the outer surface of the first lower sealing head **2730** ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The outer sealing mandrel **1935** preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The first outer sealing mandrel **2735** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the first outer sealing mandrel **2735** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The first outer sealing mandrel **2735** may be coupled to the first upper sealing head **2725** using any number of conventional commercially available mechanical couplings such as, for example, oilfield country tubular goods, welding, amorphous bonding, or a standard threaded connection. In an exemplary embodiment, the first outer sealing mandrel **2735** is removably coupled to the first upper sealing head **2725** by a standard threaded connection. The first outer sealing mandrel **2735** may be coupled to the second upper sealing head **2745** using any number of conventional commercially available mechanical couplings such as, for example, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In an exemplary embodiment, the first outer sealing mandrel **2735** is removably coupled to the second upper sealing head **2745** by a standard threaded connection.

The second inner sealing mandrel **2740** is coupled to the first lower sealing head **2730** and the second lower sealing head **2750**. The second inner sealing mandrel **2740** preferably comprises a substantially hollow tubular member or members. The second inner sealing mandrel **2740** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the second inner sealing mandrel **2740** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The second inner sealing mandrel **2740** may be coupled to the first lower sealing head **2730** using any number of conventional commercially available mechanical couplings such as, for example, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In an exemplary embodiment, the second inner sealing mandrel **2740** is removably coupled to the first lower sealing head **2740** by a standard threaded connection. The mechanical coupling between the second inner sealing mandrel **2740** and the first lower sealing head **2730** preferably includes sealing members **2860**.

The second inner sealing mandrel **2740** may be coupled to the second lower sealing head **2750** using any number of conventional commercially available mechanical couplings such as, for example, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In an exemplary embodiment, the second inner sealing mandrel **2720** is removably coupled to the second lower sealing head **2750** by a standard threaded connection. In an exemplary embodiment, the mechanical coupling between the second inner sealing mandrel **2740** and the second lower sealing head **2750** includes

one or more sealing members **2865**. The sealing members **2865** may comprise any number of conventional commercially available seals such as, for example, o-rings, polypak seals or metal spring energized seals. In an exemplary embodiment, the sealing members **2865** comprise polypak seals available from Parker Seals.

The second inner sealing mandrel **2740** preferably includes a fluid passage **2810** that is adapted to convey fluidic materials from the fluid passage **2805** into the fluid passage **2815**. In an exemplary embodiment, the fluid passage **2810** is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The second upper sealing head **2745** is coupled to the first upper sealing head **2725**, the first outer sealing mandrel **2735**, the second outer sealing mandrel **2755**, and the expansion cone **2765**. The second upper sealing head **2745** is also movably coupled to the outer surface of the second inner sealing mandrel **2740** and the inner surface of the casing **2790**. In this manner, the second upper sealing head **2745** reciprocates in the axial direction. The radial clearance between the inner cylindrical surface of the second upper sealing head **2745** and the outer surface of the second inner sealing mandrel **2740** may range, for example, from about 0.0025 to 0.05 inches. In an exemplary embodiment, the radial clearance between the inner cylindrical surface of the second upper sealing head **2745** and the outer surface of the second inner sealing mandrel **2740** ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance. The radial clearance between the outer cylindrical surface of the second upper sealing head **2745** and the inner surface of the casing **2790** may range, for example, from about 0.025 to 0.375 inches. In an exemplary embodiment, the radial clearance between the outer cylindrical surface of the second upper sealing head **2745** and the inner surface of the casing **2790** ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone **2765** during the expansion process.

The second upper sealing head **2745** preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The second upper sealing head **2745** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the second upper sealing head **2745** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The inner surface of the second upper sealing head **2745** preferably includes one or more annular sealing members **2870** for sealing the interface between the second upper sealing head **2745** and the second inner sealing mandrel **2740**. The sealing members **2870** may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In an exemplary embodiment, the sealing members **2870** comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

In an exemplary embodiment, the second upper sealing head **2745** includes a shoulder **2875** for supporting the second upper sealing head **2745** on the second lower sealing head **2750**.

The second upper sealing head **2745** may be coupled to the first outer sealing mandrel **2735** using any number of conventional commercially available mechanical couplings

such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In an exemplary embodiment, the second upper sealing head 2745 is removably coupled to the first outer sealing mandrel 2735 by a standard threaded connection. In an exemplary embodiment, the mechanical coupling between the second upper sealing head 2745 and the first outer sealing mandrel 2735 includes one or more sealing members 2880 for fluidically sealing the interface between the second upper sealing head 2745 and the first outer sealing mandrel 2735. The sealing members 2880 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In an exemplary embodiment, the sealing members 2880 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The second upper sealing head 2745 may be coupled to the second outer sealing mandrel 2755 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In an exemplary embodiment, the second upper sealing head 2745 is removably coupled to the second outer sealing mandrel 2755 by a standard threaded connection. In an exemplary embodiment, the mechanical coupling between the second upper sealing head 2745 and the second outer sealing mandrel 2755 includes one or more sealing members 2885 for fluidically sealing the interface between the second upper sealing head 2745 and the second outer sealing mandrel 2755. The sealing members 2885 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In an exemplary embodiment, the sealing members 2885 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

The second lower sealing head 2750 is coupled to the second inner sealing mandrel 2740 and the load mandrel 2760. The second lower sealing head 2750 is also movably coupled to the inner surface of the second outer sealing mandrel 2755. In this manner, the first upper sealing head 2725, the first outer sealing mandrel 2735, second upper sealing head 2745, second outer sealing mandrel 2755, and the expansion cone 2765 reciprocate in the axial direction. The radial clearance between the outer surface of the second lower sealing head 2750 and the inner surface of the second outer sealing mandrel 2755 may range, for example, from about 0.0025 to 0.05 inches. In an exemplary embodiment, the radial clearance between the outer surface of the second lower sealing head 2750 and the inner surface of the second outer sealing mandrel 2755 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The second lower sealing head 2750 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The second lower sealing head 2750 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the second lower sealing head 2750 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The outer surface of the second lower sealing head 2750 preferably includes one or more annular sealing mem-

bers 2890 for sealing the interface between the second lower sealing head 2750 and the second outer sealing mandrel 2755. The sealing members 2890 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In an exemplary embodiment, the sealing members 2890 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

The second lower sealing head 2750 may be coupled to the second inner sealing mandrel 2740 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In an exemplary embodiment, the second lower sealing head 2750 is removably coupled to the second inner sealing mandrel 2740 by a standard threaded connection. In an exemplary embodiment, the mechanical coupling between the second lower sealing head 2750 and the second inner sealing mandrel 2740 includes one or more sealing members 2895 for fluidically sealing the interface between the second sealing head 2750 and the second sealing mandrel 2740. The sealing members 2895 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In an exemplary embodiment, the sealing members 2895 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The second lower sealing head 2750 may be coupled to the load mandrel 2760 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield tubular goods specialty threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In an exemplary embodiment, the second lower sealing head 2750 is removably coupled to the load mandrel 2760 by a standard threaded connection. In an exemplary embodiment, the mechanical coupling between the second lower sealing head 2750 and the load mandrel 2760 includes one or more sealing members 2900 for fluidically sealing the interface between the second lower sealing head 2750 and the load mandrel 2760. The sealing members 2900 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In an exemplary embodiment, the sealing members 2900 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

In an exemplary embodiment, the second lower sealing head 2750 includes a throat passage 2905 fluidically coupled between the fluid passages 2810 and 2815. The throat passage 2905 is preferably of reduced size and is adapted to receive and engage with a plug 2910, or other similar device. In this manner, the fluid passage 2810 is fluidically isolated from the fluid passage 2815. In this manner, the pressure chambers 2915 and 2920 are pressurized. The use of a plurality of pressure chambers in the apparatus 2700 permits the effective driving force to be multiplied. While illustrated using a pair of pressure chambers, 2915 and 2920, the apparatus 2700 may be further modified to employ additional pressure chambers.

The second outer sealing mandrel 2755 is coupled to the first upper sealing head 2725, the first outer sealing mandrel 2735, the second upper sealing head 2745, and the expansion cone 2765. The second outer sealing mandrel 2755 is

also movably coupled to the inner surface of the casing **2790** and the outer surface of the second lower sealing head **2750**. In this manner, the first upper sealing head **2725**, first outer sealing mandrel **2735**, second upper sealing head **2745**, second outer sealing mandrel **2755**, and the expansion cone **2765** reciprocate in the axial direction.

The radial clearance between the outer surface of the second outer sealing mandrel **2755** and the inner surface of the casing **2790** may range, for example, from about 0.025 to 0.375 inches. In an exemplary embodiment, the radial clearance between the outer surface of the second outer sealing mandrel **2755** and the inner surface of the casing **2790** ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone **2765** during the expansion process. The radial clearance between the inner surface of the second outer sealing mandrel **2755** and the outer surface of the second lower sealing head **2750** may range, for example, from about 0.0025 to 0.05 inches. In an exemplary embodiment, the radial clearance between the inner surface of the second outer sealing mandrel **2755** and the outer surface of the second lower sealing head **2750** ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The second outer sealing mandrel **2755** preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The second outer sealing mandrel **2755** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the second outer sealing mandrel **2755** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The second outer sealing mandrel **2755** may be coupled to the second upper sealing head **2745** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In an exemplary embodiment, the second outer sealing mandrel **2755** is removably coupled to the second upper sealing head **2745** by a standard threaded connection. The second outer sealing mandrel **2755** may be coupled to the expansion cone **2765** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In an exemplary embodiment, the second outer sealing mandrel **2755** is removably coupled to the expansion cone **2765** by a standard threaded connection.

The load mandrel **2760** is coupled to the second lower sealing head **2750** and the mechanical slip body **2775**. The load mandrel **2760** preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The load mandrel **2760** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the load mandrel **2760** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The load mandrel **2760** may be coupled to the second lower sealing head **2750** using any number of conventional commercially available mechanical couplings such as, for

example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In an exemplary embodiment, the load mandrel **2760** is removably coupled to the second lower sealing head **2750** by a standard threaded connection. The load mandrel **2760** may be coupled to the mechanical slip body **2775** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In an exemplary embodiment, the load mandrel **2760** is removably coupled to the mechanical slip body **2775** by a standard threaded connection.

The load mandrel **2760** preferably includes a fluid passage **2815** that is adapted to convey fluidic materials from the fluid passage **2810** to the fluid passage **2820**. In an exemplary embodiment, the fluid passage **2815** is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The expansion cone **2765** is coupled to the second outer sealing mandrel **2755**. The expansion cone **2765** is also movably coupled to the inner surface of the casing **2790**. In this manner, the first upper sealing head **2725**, first outer sealing mandrel **2735**, second upper sealing head **2745**, second outer sealing mandrel **2755**, and the expansion cone **2765** reciprocate in the axial direction. The reciprocation of the expansion cone **2765** causes the casing **2790** to expand in the radial direction.

The expansion cone **2765** preferably comprises an annular member having substantially cylindrical inner and conical outer surfaces. The outside radius of the outside conical surface may range, for example, from about 2 to 34 inches. In an exemplary embodiment, the outside radius of the outside conical surface ranges from about 3 to 28 inches in order to optimally provide expansion cone dimensions that accommodate the typical range of casings. The axial length of the expansion cone **2765** may range, for example, from about 2 to 8 times the largest outer diameter of the expansion cone **2765**. In an exemplary embodiment, the axial length of the expansion cone **2765** ranges from about 3 to 5 times the largest outer diameter of the expansion cone **2765** in order to optimally provide stabilization and centralization of the expansion cone **2765**. In an exemplary embodiment, the angle of attack of the expansion cone **2765** ranges from about 5 to 30 degrees in order to optimally balance frictional forces and radial expansion forces.

The expansion cone **2765** may be fabricated from any number of conventional commercially available materials such as, for example, machine tool steel, nitride steel, titanium, tungsten carbide, ceramics or other similar high strength materials. In an exemplary embodiment, the expansion cone **2765** is fabricated from D2 machine tool steel in order to optimally provide high strength and resistance to corrosion and galling. In an exemplary embodiment, the outside surface of the expansion cone **2765** has a surface hardness ranging from about 58 to 62 Rockwell C in order to optimally provide high strength and resistance to wear and galling.

The expansion cone **2765** may be coupled to the second outer sealing mandrel **2755** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In an

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exemplary embodiment, the expansion cone 2765 is coupled to the second outside sealing mandrel 2765 using a standard threaded connection in order to optimally provide high strength and easy replacement of the expansion cone 2765.

The mandrel launcher 2770 is coupled to the casing 2790. The mandrel launcher 2770 comprises a tubular section of casing having a reduced wall thickness compared to the casing 2790. In an exemplary embodiment, the wall thickness of the mandrel launcher 2770 is about 50 to 100% of the wall thickness of the casing 2790. The wall thickness of the mandrel launcher 2770 may range, for example, from about 0.15 to 1.5 inches. In an exemplary embodiment, the wall thickness of the mandrel launcher 2770 ranges from about 0.25 to 0.75 inches. In this manner, the initiation of the radial expansion of the casing 2790 is facilitated, the placement of the apparatus 2700 within a wellbore casing and wellbore is facilitated, and the mandrel launcher 2770 has a burst strength approximately equal to that of the casing 2790.

The mandrel launcher 2770 may be coupled to the casing 2790 using any number of conventional mechanical couplings such as, for example, a standard threaded connection. The mandrel launcher 2770 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel, or other similar high strength materials. In an exemplary embodiment, the mandrel launcher 2770 is fabricated from oilfield country tubular goods of higher strength than that of the casing 2790 but with a reduced wall thickness in order to optimally provide a small compact tubular container having a burst strength approximately equal to that of the casing 2790.

The mechanical slip body 2775 is coupled to the load mandrel 2760, the mechanical slips 2780, and the drag blocks 2785. The mechanical slip body 2775 preferably comprises a tubular member having an inner passage 2820 fluidly coupled to the passage 2815. In this manner, fluidic materials may be conveyed from the passage 2820 to a region outside of the apparatus 2700.

The mechanical slip body 2775 may be coupled to the load mandrel 2760 using any number of conventional mechanical couplings. In an exemplary embodiment, the mechanical slip body 2775 is removably coupled to the load mandrel 2760 using a standard threaded connection in order to optimally provide high strength and easy disassembly. The mechanical slip body 2775 may be coupled to the mechanical slips 2780 using any number of conventional mechanical couplings. In an exemplary embodiment, the mechanical slip body 2775 is removably coupled to the mechanical slips 2780 using threaded connections and sliding steel retainer rings in order to optimally provide a high strength attachment. The mechanical slip body 2775 may be coupled to the drag blocks 2785 using any number of conventional mechanical couplings. In an exemplary embodiment, the mechanical slip body 2775 is removably coupled to the drag blocks 2785 using threaded connections and sliding steel retainer rings in order to optimally provide a high strength attachment.

The mechanical slip body 2775 preferably includes a fluid passage 2820 that is adapted to convey fluidic materials from the fluid passage 2815 to the region outside of the apparatus 2700. In an exemplary embodiment, the fluid passage 2820 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The mechanical slips 2780 are coupled to the outside surface of the mechanical slip body 2775. During operation

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of the apparatus 2700, the mechanical slips 2780 prevent upward movement of the casing 2790 and mandrel launcher 2770. In this manner, during the axial reciprocation of the expansion cone 2765, the casing 2790 and mandrel launcher 2770 are maintained in a substantially stationary position. In this manner, the mandrel launcher 2765 and casing 2790 and mandrel launcher 2770 are expanded in the radial direction by the axial movement of the expansion cone 2765.

The mechanical slips 2780 may comprise any number of conventional commercially available mechanical slips such as, for example, RTTS packer tungsten carbide mechanical slips, RTTS packer wicker type mechanical slips or Model 3L retrievable bridge plug tungsten carbide upper mechanical slips. In an exemplary embodiment, the mechanical slips 2780 comprise RTTS packer tungsten carbide mechanical slips available from Halliburton Energy Services in order to optimally provide resistance to axial movement of the casing 2790 and mandrel launcher 2770 during the expansion process.

The drag blocks 2785 are coupled to the outside surface of the mechanical slip body 2775. During operation of the apparatus 2700, the drag blocks 2785 prevent upward movement of the casing 2790 and mandrel launcher 2770. In this manner, during the axial reciprocation of the expansion cone 2765, the casing 2790 and mandrel launcher 2770 are maintained in a substantially stationary position. In this manner, the mandrel launcher 2770 and casing 2790 are expanded in the radial direction by the axial movement of the expansion cone 2765.

The drag blocks 2785 may comprise any number of conventional commercially available mechanical slips such as, for example, RTTS packer mechanical drag blocks or Model 3L retrievable bridge plug drag blocks. In an exemplary embodiment, the drag blocks 2785 comprise RTTS packer mechanical drag blocks available from Halliburton Energy Services in order to optimally provide resistance to axial movement of the casing 2790 and mandrel launcher 2770 during the expansion process.

The casing 2790 is coupled to the mandrel launcher 2770. The casing 2790 is further removably coupled to the mechanical slips 2780 and drag blocks 2785. The casing 2790 preferably comprises a tubular member. The casing 2790 may be fabricated from any number of conventional commercially available materials such as, for example, slotted tubulars, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the casing 2790 is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills in order to optimally provide high strength using standardized materials. In an exemplary embodiment, the upper end of the casing 2790 includes one or more sealing members positioned about the exterior of the casing 2790.

During operation, the apparatus 2700 is positioned in a wellbore with the upper end of the casing 2790 positioned in an overlapping relationship within an existing wellbore casing. In order to minimize surge pressures within the borehole during placement of the apparatus 2700, the fluid passage 2795 is preferably provided with one or more pressure relief passages. During the placement of the apparatus 2700 in the wellbore, the casing 2790 is supported by the expansion cone 2765.

After positioning of the apparatus 2700 within the bore hole in an overlapping relationship with an existing section of wellbore casing, a first fluidic material is pumped into the fluid passage 2795 from a surface location. The first fluidic material is conveyed from the fluid passage 2795 to the fluid

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passages **2800**, **2802**, **2805**, **2810**, **2815**, and **2820**. The first fluidic material will then exit the apparatus **2700** and fill the annular region between the outside of the apparatus **2700** and the interior walls of the bore hole.

The first fluidic material may comprise any number of conventional commercially available materials such as, for example, epoxy, drilling mud, slag mix, water or cement. In an exemplary embodiment, the first fluidic material comprises a hardenable fluidic sealing material such as, for example, slag mix, epoxy, or cement. In this manner, a wellbore casing having an outer annular layer of a hardenable material may be formed.

The first fluidic material may be pumped into the apparatus **2700** at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 3,000 gallons/minute. In an exemplary embodiment, the first fluidic material is pumped into the apparatus **2700** at operating pressures and flow rates ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to optimally provide operational efficiency.

At a predetermined point in the injection of the first fluidic material such as, for example, after the annular region outside of the apparatus **2700** has been filled to a predetermined level, a plug **2910**, dart, or other similar device is introduced into the first fluidic material. The plug **2910** lodges in the throat passage **2905** thereby fluidically isolating the fluid passage **2810** from the fluid passage **2815**.

After placement of the plug **2910** in the throat passage **2905**, a second fluidic material is pumped into the fluid passage **2795** in order to pressurize the pressure chambers **2915** and **2920**. The second fluidic material may comprise any number of conventional commercially available materials such as, for example, water, drilling gases, drilling mud or lubricants. In an exemplary embodiment, the second fluidic material comprises a non-hardenable fluidic material such as, for example, water, drilling mud or lubricant. The use of lubricant optimally provides lubrication of the moving parts of the apparatus **2700**.

The second fluidic material may be pumped into the apparatus **2700** at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 4,500 gallons/minute. In an exemplary embodiment, the second fluidic material is pumped into the apparatus **2700** at operating pressures and flow rates ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to optimally provide operational efficiency.

The pressurization of the pressure chambers **2915** and **2920** cause the upper sealing heads, **2725** and **2745**, outer sealing mandrels, **2735** and **2755**, and expansion cone **2765** to move in an axial direction. As the expansion cone **2765** moves in the axial direction, the expansion cone **2765** pulls the mandrel launcher **2770**, casing **2790**, and drag blocks **2785** along, which sets the mechanical slips **2780** and stops further axial movement of the mandrel launcher **2770** and casing **2790**. In this manner, the axial movement of the expansion cone **2765** radially expands the mandrel launcher **2770** and casing **2790**.

Once the upper sealing heads, **2725** and **2745**, outer sealing mandrels, **2735** and **2755**, and expansion cone **2765** complete an axial stroke, the operating pressure of the second fluidic material is reduced and the drill string **2705** is raised. This causes the inner sealing mandrels, **2720** and **2740**, lower sealing heads, **2730** and **2750**, load mandrel **2760**, and mechanical slip body **2755** to move upward. This unsets the mechanical slips **2780** and permits the mechanical slips **2780** and drag blocks **2785** to be moved upward within the mandrel launcher **2770** and casing **2790**. When the lower

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sealing heads, **2730** and **2750**, contact the upper sealing heads, **2725** and **2745**, the second fluidic material is again pressurized and the radial expansion process continues. In this manner, the mandrel launcher **2770** and casing **2790** are radially expanded through repeated axial strokes of the upper sealing heads, **2725** and **2745**, outer sealing mandrels, **2735** and **2755**, and expansion cone **2765**. Throughout the radial expansion process, the upper end of the casing **2790** is preferably maintained in an overlapping relation with an existing section of wellbore casing.

At the end of the radial expansion process, the upper end of the casing **2790** is expanded into intimate contact with the inside surface of the lower end of the existing wellbore casing. In an exemplary embodiment, the sealing members provided at the upper end of the casing **2790** provide a fluidic seal between the outside surface of the upper end of the casing **2790** and the inside surface of the lower end of the existing wellbore casing. In an exemplary embodiment, the contact pressure between the casing **2790** and the existing section of wellbore casing ranges from about 400 to 10,000 in order to optimally provide contact pressure for activating the sealing members, provide optimal resistance to axial movement of the expanded casing, and optimally resist typical tensile and compressive loads on the expanded casing.

In an exemplary embodiment, as the expansion cone **2765** nears the end of the casing **2790**, the operating pressure of the second fluidic material is reduced in order to minimize shock to the apparatus **2700**. In an alternative embodiment, the apparatus **2700** includes a shock absorber for absorbing the shock created by the completion of the radial expansion of the casing **2790**.

In an exemplary embodiment, the reduced operating pressure of the second fluidic material ranges from about 100 to 1,000 psi as the expansion cone **2765** nears the end of the casing **2790** in order to optimally provide reduced axial movement and velocity of the expansion cone **2765**. In an exemplary embodiment, the operating pressure of the second fluidic material is reduced during the return stroke of the apparatus **2700** to the range of about 0 to 500 psi in order to minimize the resistance to the movement of the expansion cone **2765** during the return stroke. In an exemplary embodiment, the stroke length of the apparatus **2700** ranges from about 10 to 45 feet in order to optimally provide equipment that can be easily handled by typical oil well rigging equipment and minimize the frequency at which the apparatus **2700** must be re-stroked during an expansion operation.

In an alternative embodiment, at least a portion of the upper sealing heads, **2725** and **2745**, include expansion cones for radially expanding the mandrel launcher **2770** and casing **2790** during operation of the apparatus **2700** in order to increase the surface area of the casing **2790** acted upon during the radial expansion process. In this manner, the operating pressures can be reduced.

In an alternative embodiment, mechanical slips are positioned in an axial location between the sealing sleeve **1915** and the first inner sealing mandrel **2720** in order to optimally provide a simplified assembly and operation of the apparatus **2700**.

Upon the complete radial expansion of the casing **2790**, if applicable, the first fluidic material is permitted to cure within the annular region between the outside of the expanded casing **2790** and the interior walls of the wellbore. In the case where the casing **2790** is slotted, the cured fluidic material preferably permeates and envelops the expanded casing **2790**. In this manner, a new section of wellbore

casing is formed within a wellbore. Alternatively, the apparatus 2700 may be used to join a first section of pipeline to an existing section of pipeline. Alternatively, the apparatus 2700 may be used to directly line the interior of a wellbore with a casing, without the use of an outer annular layer of a hardenable material. Alternatively, the apparatus 2700 may be used to expand a tubular support member in a hole.

During the radial expansion process, the pressurized areas of the apparatus 2700 are limited to the fluid passages 2795, 2800, 2802, 2805, and 2810, and the pressure chambers 2915 and 2920. No fluid pressure acts directly on the mandrel launcher 2770 and casing 2790. This permits the use of operating pressures higher than the mandrel launcher 2770 and casing 2790 could normally withstand.

Referring now to FIG. 20, an exemplary embodiment of an apparatus 3000 for forming a mono-diameter wellbore casing will be described. The apparatus 3000 preferably includes a drillpipe 3005, an innerstring adapter 3010, a sealing sleeve 3015, a first inner sealing mandrel 3020, hydraulic slips 3025, a first upper sealing head 3030, a first lower sealing head 3035, a first outer sealing mandrel 3040, a second inner sealing mandrel 3045, a second upper sealing head 3050, a second lower sealing head 3055, a second outer sealing mandrel 3060, load mandrel 3065, expansion cone 3070, casing 3075, and fluid passages 3080, 3085, 3090, 3095, 3100, 3105, 3110, 3115 and 3120.

The drillpipe 3005 is coupled to the innerstring adapter 3010. During operation of the apparatus 3000, the drillpipe 3005 supports the apparatus 3000. The drillpipe 3005 preferably comprises a substantially hollow tubular member or members. The drillpipe 3005 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the drillpipe 3005 is fabricated from coiled tubing in order to facilitate the placement of the apparatus 3000 in non-vertical wellbores. The drillpipe 3005 may be coupled to the innerstring adapter 3010 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. In an exemplary embodiment, the drillpipe 3005 is removably coupled to the innerstring adapter 3010 by a drillpipe connection.

The drillpipe 3005 preferably includes a fluid passage 3080 that is adapted to convey fluidic materials from a surface location into the fluid passage 3085. In an exemplary embodiment, the fluid passage 3080 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The innerstring adapter 3010 is coupled to the drill string 3005 and the sealing sleeve 3015. The innerstring adapter 3010 preferably comprises a substantially hollow tubular member or members. The innerstring adapter 3010 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel, or other similar high strength materials. In an exemplary embodiment, the innerstring adapter 3010 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The innerstring adapter 3010 may be coupled to the drill string 3005 using any number of conventional commercially available mechanical couplings such as, for example, drill-

pipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In an exemplary embodiment, the innerstring adapter 3010 is removably coupled to the drill pipe 3005 by a drillpipe connection. The innerstring adapter 3010 may be coupled to the sealing sleeve 3015 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In an exemplary embodiment, the innerstring adapter 3010 is removably coupled to the sealing sleeve 3015 by a standard threaded connection.

The innerstring adapter 3010 preferably includes a fluid passage 3085 that is adapted to convey fluidic materials from the fluid passage 3080 into the fluid passage 3090. In an exemplary embodiment, the fluid passage 3085 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The sealing sleeve 3015 is coupled to the innerstring adapter 3010 and the first inner sealing mandrel 3020. The sealing sleeve 3015 preferably comprises a substantially hollow tubular member or members. The sealing sleeve 3015 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the sealing sleeve 3015 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The sealing sleeve 3015 may be coupled to the innerstring adapter 3010 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type connection or a standard threaded connection. In an exemplary embodiment, the sealing sleeve 3015 is removably coupled to the innerstring adapter 3010 by a standard threaded connection. The sealing sleeve 3015 may be coupled to the first inner sealing mandrel 3020 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In an exemplary embodiment, the sealing sleeve 3015 is removably coupled to the first inner sealing mandrel 3020 by a standard threaded connection.

The sealing sleeve 3015 preferably includes a fluid passage 3090 that is adapted to convey fluidic materials from the fluid passage 3085 into the fluid passage 3095. In an exemplary embodiment, the fluid passage 3090 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The first inner sealing mandrel 3020 is coupled to the sealing sleeve 3015, the hydraulic slips 3025, and the first lower sealing head 3035. The first inner sealing mandrel 3020 is further movably coupled to the first upper sealing head 3030. The first inner sealing mandrel 3020 preferably comprises a substantially hollow tubular member or members. The first inner sealing mandrel 3020 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel, or similar

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high strength materials. In an exemplary embodiment, the first inner sealing mandrel **3020** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The first inner sealing mandrel **3020** may be coupled to the sealing sleeve **3015** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In an exemplary embodiment, the first inner sealing mandrel **3020** is removably coupled to the sealing sleeve **3015** by a standard threaded connection. The first inner sealing mandrel **3020** may be coupled to the hydraulic slips **3025** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In an exemplary embodiment, the first inner sealing mandrel **3020** is removably coupled to the hydraulic slips **3025** by a standard threaded connection. The first inner sealing mandrel **3020** may be coupled to the first lower sealing head **3035** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In an exemplary embodiment, the first inner sealing mandrel **3020** is removably coupled to the first lower sealing head **3035** by a standard threaded connection.

The first inner sealing mandrel **3020** preferably includes a fluid passage **3095** that is adapted to convey fluidic materials from the fluid passage **3090** into the fluid passage **3100**. In an exemplary embodiment, the fluid passage **3095** is adapted to convey fluidic materials such as, for example, water, drilling mud, cement, epoxy, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The first inner sealing mandrel **3020** further preferably includes fluid passages **3110** that are adapted to convey fluidic materials from the fluid passage **3095** into the pressure chambers of the hydraulic slips **3025**. In this manner, the slips **3025** are activated upon the pressurization of the fluid passage **3095** into contact with the inside surface of the casing **3075**. In an exemplary embodiment, the fluid passages **3110** are adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling fluids or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The first inner sealing mandrel **3020** further preferably includes fluid passages **3115** that are adapted to convey fluidic materials from the fluid passage **3095** into the first pressure chamber **3175** defined by the first upper sealing head **3030**, the first lower sealing head **3035**, the first inner sealing mandrel **3020**, and the first outer sealing mandrel **3040**. During operation of the apparatus **3000**, pressurization of the pressure chamber **3175** causes the first upper sealing head **3030**, the first outer sealing mandrel **3040**, the second upper sealing head **3050**, the second outer sealing mandrel **3060**, and the expansion cone **3070** to move in an axial direction.

The slips **3025** are coupled to the outside surface of the first inner sealing mandrel **3020**. During operation of the apparatus **3000**, the slips **3025** are activated upon the pressurization of the fluid passage **3095** into contact with the

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inside surface of the casing **3075**. In this manner, the slips **3025** maintain the casing **3075** in a substantially stationary position.

The slips **3025** preferably include fluid passages **3125**, pressure chambers **3130**, spring bias **3135**, and slip members **3140**. The slips **3025** may comprise any number of conventional commercially available hydraulic slips such as, for example, RTTS packer tungsten carbide hydraulic slips or Model 3L retrievable bridge plug with hydraulic slips. In an exemplary embodiment, the slips **3025** comprise RTTS packer tungsten carbide hydraulic slips available from Halliburton Energy Services in order to optimally provide resistance to axial movement of the casing **3075** during the expansion process.

The first upper sealing head **3030** is coupled to the first outer sealing mandrel **3040**, the second upper sealing head **3050**, the second outer sealing mandrel **3060**, and the expansion cone **3070**. The first upper sealing head **3030** is also movably coupled to the outer surface of the first inner sealing mandrel **3020** and the inner surface of the casing **3075**. In this manner, the first upper sealing head **3030**, the first outer sealing mandrel **3040**, the second upper sealing head **3050**, the second outer sealing mandrel **3060**, and the expansion cone **3070** reciprocate in the axial direction.

The radial clearance between the inner cylindrical surface of the first upper sealing head **3030** and the outer surface of the first inner sealing mandrel **3020** may range, for example, from about 0.0025 to 0.05 inches. In an exemplary embodiment, the radial clearance between the inner cylindrical surface of the first upper sealing head **3030** and the outer surface of the first inner sealing mandrel **3020** ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance. The radial clearance between the outer cylindrical surface of the first upper sealing head **3030** and the inner surface of the casing **3075** may range, for example, from about 0.025 to 0.375 inches. In an exemplary embodiment, the radial clearance between the outer cylindrical surface of the first upper sealing head **3030** and the inner surface of the casing **3075** ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone **3070** during the expansion process.

The first upper sealing head **3030** preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The first upper sealing head **3030** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, or other similar high strength materials. In an exemplary embodiment, the first upper sealing head **3030** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The inner surface of the first upper sealing head **3030** preferably includes one or more annular sealing members **3145** for sealing the interface between the first upper sealing head **3030** and the first inner sealing mandrel **3020**. The sealing members **3145** may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In an exemplary embodiment, the sealing members **3145** comprise polypak seals available from Parker seals in order to optimally provide sealing for a long axial stroke.

In an exemplary embodiment, the first upper sealing head **3030** includes a shoulder **3150** for supporting the first upper sealing head **3030**, first outer sealing mandrel **3040**, second upper sealing head **3050**, second outer sealing mandrel **3060**, and expansion cone **3070** on the first lower sealing head **3035**.

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The first upper sealing head **3030** may be coupled to the first outer sealing mandrel **3040** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In an exemplary embodiment, the first upper sealing head **3030** is removably coupled to the first outer sealing mandrel **3040** by a standard threaded connection. In an exemplary embodiment, the mechanical coupling between the first upper sealing head **3030** and the first outer sealing mandrel **3040** includes one or more sealing members **3155** for fluidically sealing the interface between the first upper sealing head **3030** and the first outer sealing mandrel **3040**. The sealing members **3155** may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In an exemplary embodiment, the sealing members **3155** comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The first lower sealing head **3035** is coupled to the first inner sealing mandrel **3020** and the second inner sealing mandrel **3045**. The first lower sealing head **3035** is also movably coupled to the inner surface of the first outer sealing mandrel **3040**. In this manner, the first upper sealing head **3030**, first outer sealing mandrel **3040**, second upper sealing head **3050**, second outer sealing mandrel **3060**, and expansion cone **3070** reciprocate in the axial direction. The radial clearance between the outer surface of the first lower sealing head **3035** and the inner surface of the first outer sealing mandrel **3040** may range, for example, from about 0.0025 to 0.05 inches. In an exemplary embodiment, the radial clearance between the outer surface of the first lower sealing head **3035** and the inner surface of the outer sealing mandrel **3040** ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The first lower sealing head **3035** preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The first lower sealing head **3035** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the first lower sealing head **3035** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The outer surface of the first lower sealing head **3035** preferably includes one or more annular sealing members **3160** for sealing the interface between the first lower sealing head **3035** and the first outer sealing mandrel **3040**. The sealing members **3160** may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In an exemplary embodiment, the sealing members **3160** comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The first lower sealing head **3035** may be coupled to the first inner sealing mandrel **3020** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In an exemplary embodiment, the first lower sealing head **3035** is removably coupled to the first inner sealing mandrel **3020** by a standard threaded connection. In an exemplary embodiment, the mechanical coupling between

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the first lower sealing head **3035** and the first inner sealing mandrel **3020** includes one or more sealing members **3165** for fluidically sealing the interface between the first lower sealing head **3035** and the first inner sealing mandrel **3020**. The sealing members **3165** may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In an exemplary embodiment, the sealing members **3165** comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke length.

The first lower sealing head **3035** may be coupled to the second inner sealing mandrel **3045** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In an exemplary embodiment, the first lower sealing head **3035** is removably coupled to the second inner sealing mandrel **3045** by a standard threaded connection. In an exemplary embodiment, the mechanical coupling between the first lower sealing head **3035** and the second inner sealing mandrel **3045** includes one or more sealing members **3170** for fluidically sealing the interface between the first lower sealing head **3035** and the second inner sealing mandrel **3045**. The sealing members **3170** may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In an exemplary embodiment, the sealing members **3170** comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The first outer sealing mandrel **3040** is coupled to the first upper sealing head **3030** and the second upper sealing head **3050**. The first outer sealing mandrel **3040** is also movably coupled to the inner surface of the casing **3075** and the outer surface of the first lower sealing head **3035**. In this manner, the first upper sealing head **3030**, first outer sealing mandrel **3040**, second upper sealing head **3050**, second outer sealing mandrel **3060**, and the expansion cone **3070** reciprocate in the axial direction. The radial clearance between the outer surface of the first outer sealing mandrel **3040** and the inner surface of the casing **3075** may range, for example, from about 0.025 to 0.375 inches. In an exemplary embodiment, the radial clearance between the outer surface of the first outer sealing mandrel **3040** and the inner surface of the casing **3075** ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone **3070** during the expansion process. The radial clearance between the inner surface of the first outer sealing mandrel **3040** and the outer surface of the first lower sealing head **3035** may range, for example, from about 0.005 to 0.125 inches. In an exemplary embodiment, the radial clearance between the inner surface of the first outer sealing mandrel **3040** and the outer surface of the first lower sealing head **3035** ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The first outer sealing mandrel **3040** preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The first outer sealing mandrel **3040** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the first outer sealing mandrel **3040** is

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fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The first outer sealing mandrel **3040** may be coupled to the first upper sealing head **3030** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In an exemplary embodiment, the first outer sealing mandrel **3040** is removably coupled to the first upper sealing head **3030** by a standard threaded connection. In an exemplary embodiment, the mechanical coupling between the first outer sealing mandrel **3040** and the first upper sealing head **3030** includes one or more sealing members **3180** for sealing the interface between the first outer sealing mandrel **3040** and the first upper sealing head **3030**. The sealing members **3180** may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In an exemplary embodiment, the sealing members **3180** comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The first outer sealing mandrel **3040** may be coupled to the second upper sealing head **3050** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In an exemplary embodiment, the first outer sealing mandrel **3040** is removably coupled to the second upper sealing head **3050** by a standard threaded connection. In an exemplary embodiment, the mechanical coupling between the first outer sealing mandrel **3040** and the second upper sealing head **3050** includes one or more sealing members **3185** for sealing the interface between the first outer sealing mandrel **3040** and the second upper sealing head **3050**. The sealing members **3185** may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In an exemplary embodiment, the sealing members **3185** comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The second inner sealing mandrel **3045** is coupled to the first lower sealing head **3035** and the second lower sealing head **3055**. The second inner sealing mandrel **3045** preferably comprises a substantially hollow tubular member or members. The second inner sealing mandrel **3045** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the second inner sealing mandrel **3045** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The second inner sealing mandrel **3045** may be coupled to the first lower sealing head **3035** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In an exemplary embodiment, the second inner sealing mandrel **3045** is removably coupled to the first lower sealing head **3035** by a standard threaded connection. The second inner sealing mandrel **3045** may be coupled to the

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second lower sealing head **3055** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type connection, or a standard threaded connection. In an exemplary embodiment, the second inner sealing mandrel **3045** is removably coupled to the second lower sealing head **3055** by a standard threaded connection.

The second inner sealing mandrel **3045** preferably includes a fluid passage **3100** that is adapted to convey fluidic materials from the fluid passage **3095** into the fluid passage **3105**. In an exemplary embodiment, the fluid passage **3100** is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The second inner sealing mandrel **3045** further preferably includes fluid passages **3120** that are adapted to convey fluidic materials from the fluid passage **3100** into the second pressure chamber **3190** defined by the second upper sealing head **3050**, the second lower sealing head **3055**, the second inner sealing mandrel **3045**, and the second outer sealing mandrel **3060**. During operation of the apparatus **3000**, pressurization of the second pressure chamber **3190** causes the first upper sealing head **3030**, the first outer sealing mandrel **3040**, the second upper sealing head **3050**, the second outer sealing mandrel **3060**, and the expansion cone **3070** to move in an axial direction.

The second upper sealing head **3050** is coupled to the first outer sealing mandrel **3040** and the second outer sealing mandrel **3060**. The second upper sealing head **3050** is also movably coupled to the outer surface of the second inner sealing mandrel **3045** and the inner surface of the casing **3075**. In this manner, the second upper sealing head **3050** reciprocates in the axial direction. The radial clearance between the inner cylindrical surface of the second upper sealing head **3050** and the outer surface of the second inner sealing mandrel **3045** may range, for example, from about 0.0025 to 0.05 inches. In an exemplary embodiment, the radial clearance between the inner cylindrical surface of the second upper sealing head **3050** and the outer surface of the second inner sealing mandrel **3045** ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance. The radial clearance between the outer cylindrical surface of the second upper sealing head **3050** and the inner surface of the casing **3075** may range, for example, from about 0.025 to 0.375 inches. In an exemplary embodiment, the radial clearance between the outer cylindrical surface of the second upper sealing head **3050** and the inner surface of the casing **3075** ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone **3070** during the expansion process.

The second upper sealing head **3050** preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The second upper sealing head **3050** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the second upper sealing head **3050** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The inner surface of the second upper sealing head **3050** preferably includes one or more annular sealing members **3195** for sealing the interface between the second upper sealing head **3050** and the second inner sealing mandrel **3045**. The sealing members **3195** may comprise any number

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of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In an exemplary embodiment, the sealing members 3195 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

In an exemplary embodiment, the second upper sealing head 3050 includes a shoulder 3200 for supporting the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing head 3050, second outer sealing mandrel 3060, and expansion cone 3070 on the second lower sealing head 3055.

The second upper sealing head 3050 may be coupled to the first outer sealing mandrel 3040 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In an exemplary embodiment, the second upper sealing head 3050 is removably coupled to the first outer sealing mandrel 3040 by a standard threaded connection. In an exemplary embodiment, the mechanical coupling between the second upper sealing head 3050 and the first outer sealing mandrel 3040 includes one or more sealing members 3185 for fluidically sealing the interface between the second upper sealing head 3050 and the first outer sealing mandrel 3040. The second upper sealing head 3050 may be coupled to the second outer sealing mandrel 3060 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In an exemplary embodiment, the second upper sealing head 3050 is removably coupled to the second outer sealing mandrel 3060 by a standard threaded connection. In an exemplary embodiment, the mechanical coupling between the second upper sealing head 3050 and the second outer sealing mandrel 3060 includes one or more sealing members 3205 for fluidically sealing the interface between the second upper sealing head 3050 and the second outer sealing mandrel 3060.

The second lower sealing head 3055 is coupled to the second inner sealing mandrel 3045 and the load mandrel 3065. The second lower sealing head 3055 is also movably coupled to the inner surface of the second outer sealing mandrel 3060. In this manner, the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing mandrel 3050, second outer sealing mandrel 3060, and expansion cone 3070 reciprocate in the axial direction. The radial clearance between the outer surface of the second lower sealing head 3055 and the inner surface of the second outer sealing mandrel 3060 may range, for example, from about 0.0025 to 0.05 inches. In an exemplary embodiment, the radial clearance between the outer surface of the second lower sealing head 3055 and the inner surface of the second outer sealing mandrel 3060 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The second lower sealing head 3055 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The second lower sealing head 3055 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel, or other similar high strength materials. In an exemplary embodiment, the second lower sealing head 3055 is fabricated from stainless steel in order to optimally provide

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high strength, corrosion resistance, and low friction surfaces. The outer surface of the second lower sealing head 3055 preferably includes one or more annular sealing members 3210 for sealing the interface between the second lower sealing head 3055 and the second outer sealing mandrel 3060. The sealing members 3210 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In an exemplary embodiment, the sealing members 3210 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

The second lower sealing head 3055 may be coupled to the second inner sealing mandrel 3045 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In an exemplary embodiment, the second lower sealing head 3055 is removably coupled to the second inner sealing mandrel 3045 by a standard threaded connection. In an exemplary embodiment, the mechanical coupling between the lower sealing head 3055 and the second inner sealing mandrel 3045 includes one or more sealing members 3215 for fluidically sealing the interface between the second lower sealing head 3055 and the second inner sealing mandrel 3045. The sealing members 3215 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In an exemplary embodiment, the sealing members 3215 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

The second lower sealing head 3055 may be coupled to the load mandrel 3065 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In an exemplary embodiment, the second lower sealing head 3055 is removably coupled to the load mandrel 3065 by a standard threaded connection. In an exemplary embodiment, the mechanical coupling between the second lower sealing head 3055 and the load mandrel 3065 includes one or more sealing members 3220 for fluidically sealing the interface between the second lower sealing head 3055 and the load mandrel 3065. The sealing members 3220 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In an exemplary embodiment, the sealing members 3220 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

In an exemplary embodiment, the second lower sealing head 3055 includes a throat passage 3225 fluidically coupled between the fluid passages 3100 and 3105. The throat passage 3225 is preferably of reduced size and is adapted to receive and engage with a plug 3230, or other similar device. In this manner, the fluid passage 3100 is fluidically isolated from the fluid passage 3105. In this manner, the pressure chambers 3175 and 3190 are pressurized. Furthermore, the placement of the plug 3230 in the throat passage 3225 also pressurizes the pressure chambers 3130 of the hydraulic slips 3025.

The second outer sealing mandrel 3060 is coupled to the second upper sealing head 3050 and the expansion cone 3070. The second outer sealing mandrel 3060 is also movably coupled to the inner surface of the casing 3075 and the outer surface of the second lower sealing head 3055. In this

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manner, the first upper sealing head **3030**, first outer sealing mandrel **3040**, second upper sealing head **3050**, second outer sealing mandrel **3060**, and the expansion cone **3070** reciprocate in the axial direction. The radial clearance between the outer surface of the second outer sealing mandrel **3060** and the inner surface of the casing **3075** may range, for example, from about 0.025 to 0.375 inches. In an exemplary embodiment, the radial clearance between the outer surface of the second outer sealing mandrel **3060** and the inner surface of the casing **3075** ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone **3070** during the expansion process. The radial clearance between the inner surface of the second outer sealing mandrel **3060** and the outer surface of the second lower sealing head **3055** may range, for example, from about 0.0025 to 0.05 inches. In an exemplary embodiment, the radial clearance between the inner surface of the second outer sealing mandrel **3060** and the outer surface of the second lower sealing head **3055** ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The second outer sealing mandrel **3060** preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The second outer sealing mandrel **3060** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the second outer sealing mandrel **3060** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The second outer sealing mandrel **3060** may be coupled to the second upper sealing head **3050** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In an exemplary embodiment, the outer sealing mandrel **3060** is removably coupled to the second upper sealing head **3050** by a standard threaded connection. The second outer sealing mandrel **3060** may be coupled to the expansion cone **3070** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In an exemplary embodiment, the second outer sealing mandrel **3060** is removably coupled to the expansion cone **3070** by a standard threaded connection.

The first upper sealing head **3030**, the first lower sealing head **3035**, the first inner sealing mandrel **3020**, and the first outer sealing mandrel **3040** together define the first pressure chamber **3175**. The second upper sealing head **3050**, the second lower sealing head **3055**, the second inner sealing mandrel **3045**, and the second outer sealing mandrel **3060** together define the second pressure chamber **3190**. The first and second pressure chambers, **3175** and **3190**, are fluidically coupled to the passages, **3095** and **3100**, via one or more passages, **3115** and **3120**. During operation of the apparatus **3000**, the plug **3230** engages with the throat passage **3225** to fluidically isolate the fluid passage **3100** from the fluid passage **3105**. The pressure chambers, **3175** and **3190**, are then pressurized which in turn causes the first upper sealing head **3030**, the first outer sealing mandrel **3040**, the second upper sealing head **3050**, the second outer sealing mandrel **3060**, and expansion cone **3070** to reciprocate in the axial direction. The axial motion of the expansion cone **3070** in turn

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expands the casing **3075** in the radial direction. The use of a plurality of pressure chambers, **3175** and **3190**, effectively multiplies the available driving force for the expansion cone **3070**.

The load mandrel **3065** is coupled to the second lower sealing head **3055**. The load mandrel **3065** preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The load mandrel **3065** may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In an exemplary embodiment, the load mandrel **3065** is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The load mandrel **3065** may be coupled to the lower sealing head **3055** using any number of conventional commercially available mechanical couplings such as, for example, epoxy, cement, water, drilling mud, or lubricants. In an exemplary embodiment, the load mandrel **3065** is removably coupled to the lower sealing head **3055** by a standard threaded connection.

The load mandrel **3065** preferably includes a fluid passage **3105** that is adapted to convey fluidic materials from the fluid passage **3100** to the region outside of the apparatus **3000**. In an exemplary embodiment, the fluid passage **3105** is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The expansion cone **3070** is coupled to the second outer sealing mandrel **3060**. The expansion cone **3070** is also movably coupled to the inner surface of the casing **3075**. In this manner, the first upper sealing head **3030**, first outer sealing mandrel **3040**, second upper sealing head **3050**, second outer sealing mandrel **3060**, and the expansion cone **3070** reciprocate in the axial direction. The reciprocation of the expansion cone **3070** causes the casing **3075** to expand in the radial direction.

The expansion cone **3070** preferably comprises an annular member having substantially cylindrical inner and conical outer surfaces. The outside radius of the outside conical surface may range, for example, from about 2 to 34 inches. In an exemplary embodiment, the outside radius of the outside conical surface ranges from about 3 to 28 inches in order to optimally provide an expansion cone **3070** for expanding typical casings. The axial length of the expansion cone **3070** may range, for example, from about 2 to 8 times the maximum outer diameter of the expansion cone **3070**. In an exemplary embodiment, the axial length of the expansion cone **3070** ranges from about 3 to 5 times the maximum outer diameter of the expansion cone **3070** in order to optimally provide stabilization and centralization of the expansion cone **3070** during the expansion process. In an exemplary embodiment, the maximum outside diameter of the expansion cone **3070** is between about 95 to 99% of the inside diameter of the existing wellbore that the casing **3075** will be joined with. In an exemplary embodiment, the angle of attack of the expansion cone **3070** ranges from about 5 to 30 degrees in order to optimally balance the frictional forces with the radial expansion forces.

The expansion cone **3070** may be fabricated from any number of conventional commercially available materials such as, for example, machine tool steel, nitride steel, titanium, tungsten carbide, ceramics, or other similar high strength materials. In an exemplary embodiment, the expansion cone **3070** is fabricated from D2 machine tool steel in

order to optimally provide high strength and resistance to wear and galling. In an exemplary embodiment, the outside surface of the expansion cone **3070** has a surface hardness ranging from about 58 to 62 Rockwell C in order to optimally provide high strength and resistance to wear and galling.

The expansion cone **3070** may be coupled to the second outside sealing mandrel **3060** using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type connection or a standard threaded connection. In an exemplary embodiment, the expansion cone **3070** is coupled to the second outside sealing mandrel **3060** using a standard threaded connection in order to optimally provide high strength and easy disassembly.

The casing **3075** is removably coupled to the slips **3025** and the expansion cone **3070**. The casing **3075** preferably comprises a tubular member. The casing **3075** may be fabricated from any number of conventional commercially available materials such as, for example, slotted tubulars, oilfield country tubular goods, carbon steel, low alloy steel, stainless steel, or other similar high strength materials. In an exemplary embodiment, the casing **3075** is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills in order to optimally provide high strength.

In an exemplary embodiment, the upper end **3235** of the casing **3075** includes a thin wall section **3240** and an outer annular sealing member **3245**. In an exemplary embodiment, the wall thickness of the thin wall section **3240** is about 50 to 100% of the regular wall thickness of the casing **3075**. In this manner, the upper end **3235** of the casing **3075** may be easily radially expanded and deformed into intimate contact with the lower end of an existing section of wellbore casing. In an exemplary embodiment, the lower end of the existing section of casing also includes a thin wall section. In this manner, the radial expansion of the thin walled section **3240** of casing **3075** into the thin walled section of the existing wellbore casing results in a wellbore casing having a substantially constant inside diameter.

The annular sealing member **3245** may be fabricated from any number of conventional commercially available sealing materials such as, for example, epoxy, rubber, metal or plastic. In an exemplary embodiment, the annular sealing member **3245** is fabricated from StrataLock epoxy in order to optimally provide compressibility and wear resistance. The outside diameter of the annular sealing member **3245** preferably ranges from about 70 to 95% of the inside diameter of the lower section of the wellbore casing that the casing **3075** is joined to. In this manner, after radial expansion, the annular sealing member **3245** optimally provides a fluidic seal and also preferably optimally provides sufficient frictional force with the inside surface of the existing section of wellbore casing during the radial expansion of the casing **3075** to support the casing **3075**.

In an exemplary embodiment, the lower end **3250** of the casing **3075** includes a thin wall section **3255** and an outer annular sealing member **3260**. In an exemplary embodiment, the wall thickness of the thin wall section **3255** is about 50 to 100% of the regular wall thickness of the casing **3075**. In this manner, the lower end **3250** of the casing **3075** may be easily expanded and deformed. Furthermore, in this manner, another section of casing may be easily joined with the lower end **3250** of the casing **3075** using a radial expansion process. In an exemplary embodiment, the upper end of the other section of casing also includes a thin wall section. In

this manner, the radial expansion of the thin walled section of the upper end of the other casing into the thin walled section **3255** of the lower end **3250** of the casing **3075** results in a wellbore casing having a substantially constant inside diameter.

The upper annular sealing member **3245** may be fabricated from any number of conventional commercially available sealing materials such as, for example, epoxy, rubber, metal or plastic. In an exemplary embodiment, the upper annular sealing member **3245** is fabricated from StrataLock epoxy in order to optimally provide compressibility and resistance to wear. The outside diameter of the upper annular sealing member **3245** preferably ranges from about 70 to 95% of the inside diameter of the lower section of the existing wellbore casing that the casing **3075** is joined to. In this manner, after radial expansion, the upper annular sealing member **3245** preferably provides a fluidic seal and also preferably provides sufficient frictional force with the inside wall of the wellbore during the radial expansion of the casing **3075** to support the casing **3075**.

The lower annular sealing member **3260** may be fabricated from any number of conventional commercially available sealing materials such as, for example, epoxy, rubber, metal or plastic. In an exemplary embodiment, the lower annular sealing member **3260** is fabricated from StrataLock epoxy in order to optimally provide compressibility and resistance to wear. The outside diameter of the lower annular sealing member **3260** preferably ranges from about 70 to 95% of the inside diameter of the lower section of the existing wellbore casing that the casing **3075** is joined to. In this manner, the lower annular sealing member **3260** preferably provides a fluidic seal and also preferably provides sufficient frictional force with the inside wall of the wellbore during the radial expansion of the casing **3075** to support the casing **3075**.

During operation, the apparatus **3000** is preferably positioned in a wellbore with the upper end **3235** of the casing **3075** positioned in an overlapping relationship with the lower end of an existing wellbore casing. In an exemplary embodiment, the thin wall section **3240** of the casing **3075** is positioned in opposing overlapping relation with the thin wall section and outer annular sealing member of the lower end of the existing section of wellbore casing. In this manner, the radial expansion of the casing **3075** will compress the thin wall sections and annular compressible members of the upper end **3235** of the casing **3075** and the lower end of the existing wellbore casing into intimate contact. During the positioning of the apparatus **3000** in the wellbore, the casing **3000** is preferably supported by the expansion cone **3070**.

After positioning the apparatus **3000**, a first fluidic material is then pumped into the fluid passage **3080**. The first fluidic material may comprise any number of conventional commercially available materials such as, for example, drilling mud, water, epoxy, cement, slag mix or lubricants. In an exemplary embodiment, the first fluidic material comprises a hardenable fluidic sealing material such as, for example, cement, epoxy, or slag mix in order to optimally provide a hardenable outer annular body around the expanded casing **3075**.

The first fluidic material may be pumped into the fluid passage **3080** at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 4,500 gallons/minute. In an exemplary embodiment, the first fluidic material is pumped into the fluid passage **3080** at

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operating pressures and flow rates ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to optimally provide operating efficiency.

The first fluidic material pumped into the fluid passage 3080 passes through the fluid passages 3085, 3090, 3095, 3100, and 3105 and then outside of the apparatus 3000. The first fluidic material then preferably fills the annular region between the outside of the apparatus 3000 and the interior walls of the wellbore.

The plug 3230 is then introduced into the fluid passage 3080. The plug 3230 lodges in the throat passage 3225 and fluidically isolates and blocks off the fluid passage 3100. In an exemplary embodiment, a couple of volumes of a non-hardenable fluidic material are then pumped into the fluid passage 3080 in order to remove any hardenable fluidic material contained within and to ensure that none of the fluid passages are blocked.

A second fluidic material is then pumped into the fluid passage 3080. The second fluidic material may comprise any number of conventional commercially available materials such as, for example, water, drilling gases, drilling mud or lubricant. In an exemplary embodiment, the second fluidic material comprises a non-hardenable fluidic material such as, for example, water, drilling mud, drilling gases, or lubricant in order to optimally provide pressurization of the pressure chambers 3175 and 3190.

The second fluidic material may be pumped into the fluid passage 3080 at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 4,500 gallons/minute. In an exemplary embodiment, the second fluidic material is pumped into the fluid passage 3080 at operating pressures and flow rates ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to optimally provide operational efficiency.

The second fluidic material pumped into the fluid passage 3080 passes through the fluid passages 3085, 3090, 3095, 3100 and into the pressure chambers 3130 of the slips 3025, and into the pressure chambers 3175 and 3190. Continued pumping of the second fluidic material pressurizes the pressure chambers 3130, 3175, and 3190.

The pressurization of the pressure chambers 3130 causes the hydraulic slip members 3140 to expand in the radial direction and grip the interior surface of the casing 3075. The casing 3075 is then preferably maintained in a substantially stationary position.

The pressurization of the pressure chambers 3175 and 3190 cause the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing head 3050, second outer sealing mandrel 3060, and expansion cone 3070 to move in an axial direction relative to the casing 3075. In this manner, the expansion cone 3070 will cause the casing 3075 to expand in the radial direction, beginning with the lower end 3250 of the casing 3075.

During the radial expansion process, the casing 3075 is prevented from moving in an upward direction by the slips 3025. A length of the casing 3075 is then expanded in the radial direction through the pressurization of the pressure chambers 3175 and 3190. The length of the casing 3075 that is expanded during the expansion process will be proportional to the stroke length of the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing head 3050, and expansion cone 3070.

Upon the completion of a stroke, the operating pressure of the second fluidic material is reduced and the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing head 3050, second outer sealing mandrel 3060, and expansion cone 3070 drop to their rest positions

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with the casing 3075 supported by the expansion cone 3070. The reduction in the operating pressure of the second fluidic material also causes the spring bias 3135 of the slips 3025 to pull the slip members 3140 away from the inside walls of the casing 3075.

The position of the drillpipe 3075 is preferably adjusted throughout the radial expansion process in order to maintain the overlapping relationship between the thin walled sections of the lower end of the existing wellbore casing and the upper end of the casing 3235. In an exemplary embodiment, the stroking of the expansion cone 3070 is then repeated, as necessary, until the thin walled section 3240 of the upper end 3235 of the casing 3075 is expanded into the thin walled section of the lower end of the existing wellbore casing. In this manner, a wellbore casing is formed including two adjacent sections of casing having a substantially constant inside diameter. This process may then be repeated for the entirety of the wellbore to provide a wellbore casing thousands of feet in length having a substantially constant inside diameter.

In an exemplary embodiment, during the final stroke of the expansion cone 3070, the slips 3025 are positioned as close as possible to the thin walled section 3240 of the upper end 3235 of the casing 3075 in order minimize slippage between the casing 3075 and the existing wellbore casing at the end of the radial expansion process. Alternatively, or in addition, the outside diameter of the upper annular sealing member 3245 is selected to ensure sufficient interference fit with the inside diameter of the lower end of the existing casing to prevent axial displacement of the casing 3075 during the final stroke. Alternatively, or in addition, the outside diameter of the lower annular sealing member 3260 is selected to provide an interference fit with the inside walls of the wellbore at an earlier point in the radial expansion process so as to prevent further axial displacement of the casing 3075. In this final alternative, the interference fit is preferably selected to permit expansion of the casing 3075 by pulling the expansion cone 3070 out of the wellbore, without having to pressurize the pressure chambers 3175 and 3190.

During the radial expansion process, the pressurized areas of the apparatus 3000 are preferably limited to the fluid passages 3080, 3085, 3090, 3095, 3100, 3110, 3115, 3120, the pressure chambers 3130 within the slips 3025, and the pressure chambers 3175 and 3190. No fluid pressure acts directly on the casing 3075. This permits the use of operating pressures higher than the casing 3075 could normally withstand.

Once the casing 3075 has been completely expanded off of the expansion cone 3070, the remaining portions of the apparatus 3000 are removed from the wellbore. In an exemplary embodiment, the contact pressure between the deformed thin wall sections and compressible annular members of the lower end of the existing casing and the upper end 3235 of the casing 3075 ranges from about 400 to 10,000 psi in order to optimally support the casing 3075 using the existing wellbore casing.

In this manner, the casing 3075 is radially expanded into contact with an existing section of casing by pressurizing the interior fluid passages 3080, 3085, 3090, 3095, 3100, 3110, 3115, and 3120, the pressure chambers 3130 of the slips 3025 and the pressure chambers 3175 and 3190 of the apparatus 3000.

In an exemplary embodiment, as required, the annular body of hardenable fluidic material is then allowed to cure to form a rigid outer annular body about the expanded casing 3075. In the case where the casing 3075 is slotted, the cured

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fluidic material preferably permeates and envelops the expanded casing 3075. The resulting new section of wellbore casing includes the expanded casing 3075 and the rigid outer annular body. The overlapping joint between the pre-existing wellbore casing and the expanded casing 3075 includes the deformed thin wall sections and the compressible outer annular bodies. The inner diameter of the resulting combined wellbore casings is substantially constant. In this manner, a mono-diameter wellbore casing is formed. This process of expanding overlapping tubular members having thin wall end portions with compressible annular bodies into contact can be repeated for the entire length of a wellbore. In this manner, a mono-diameter wellbore casing can be provided for thousands of feet in a subterranean formation.

In an exemplary embodiment, as the expansion cone 3070 nears the upper end 3235 of the casing 3075, the operating flow rate of the second fluidic material is reduced in order to minimize shock to the apparatus 3000. In an alternative embodiment, the apparatus 3000 includes a shock absorber for absorbing the shock created by the completion of the radial expansion of the casing 3075.

In an exemplary embodiment, the reduced operating pressure of the second fluidic material ranges from about 100 to 1,000 psi as the expansion cone 3070 nears the end of the casing 3075 in order to optimally provide reduced axial movement and velocity of the expansion cone 3070. In an exemplary embodiment, the operating pressure of the second fluidic material is reduced during the return stroke of the apparatus 3000 to the range of about 0 to 500 psi in order to minimize the resistance to the movement of the expansion cone 3070 during the return stroke. In an exemplary embodiment, the stroke length of the apparatus 3000 ranges from about 10 to 45 feet in order to optimally provide equipment that can be easily handled by typical oil well rigging equipment and also minimize the frequency at which the apparatus 3000 must be re-stroked.

In an alternative embodiment, at least a portion of one or both of the upper sealing heads, 3030 and 3050, includes an expansion cone for radially expanding the casing 3075 during operation of the apparatus 3000 in order to increase the surface area of the casing 3075 acted upon during the radial expansion process. In this manner, the operating pressures can be reduced.

Alternatively, the apparatus 3000 may be used to join a first section of pipeline to an existing section of pipeline. Alternatively, the apparatus 3000 may be used to directly line the interior of a wellbore with a casing, without the use of an outer annular layer of a hardenable material. Alternatively, the apparatus 3000 may be used to expand a tubular support member in a hole.

Referring now to FIG. 21, an apparatus 3330 for isolating subterranean zones will be described. A wellbore 3305 including a casing 3310 are positioned in a subterranean formation 3315. The subterranean formation 3315 includes a number of productive and non-productive zones, including a water zone 3320 and a targeted oil sand zone 3325. During exploration of the subterranean formation 3315, the wellbore 3305 may be extended in a well known manner to traverse the various productive and non-productive zones, including the water zone 3320 and the targeted oil sand zone 3325.

In an exemplary embodiment, in order to fluidically isolate the water zone 3320 from the targeted oil sand zone 3325, an apparatus 3330 is provided that includes one or more sections of solid casing 3335, one or more external seals

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3340, one or more sections of slotted casing 3345, one or more intermediate sections of solid casing 3350, and a solid shoe 3355.

The solid casing 3335 may provide a fluid conduit that transmits fluids and other materials from one end of the solid casing 3335 to the other end of the solid casing 3335. The solid casing 3335 may comprise any number of conventional commercially available sections of solid tubular casing such as, for example, oilfield tubulars fabricated from chromium steel or fiberglass. In an exemplary embodiment, the solid casing 3335 comprises oilfield tubulars available from various foreign and domestic steel mills.

The solid casing 3335 is preferably coupled to the casing 3310. The solid casing 3335 may be coupled to the casing 3310 using any number of conventional commercially available processes such as, for example, welding, slotted and expandable connectors, or expandable solid connectors. In an exemplary embodiment, the solid casing 3335 is coupled to the casing 3310 by using expandable solid connectors. The solid casing 3335 may comprise a plurality of such solid casings 3335.

The solid casing 3335 is preferably coupled to one more of the slotted casings 3345. The solid casing 3335 may be coupled to the slotted casing 3345 using any number of conventional commercially available processes such as, for example, welding, or slotted and expandable connectors. In an exemplary embodiment, the solid casing 3335 is coupled to the slotted casing 3345 by expandable solid connectors.

In an exemplary embodiment, the casing 3335 includes one more valve members 3360 for controlling the flow of fluids and other materials within the interior region of the casing 3335. In an alternative embodiment, during the production mode of operation, an internal tubular string with various arrangements of packers, perforated tubing, sliding sleeves, and valves may be employed within the apparatus to provide various options for commingling and isolating subterranean zones from each other while providing a fluid path to the surface.

In an exemplary embodiment, the casing 3335 is placed into the wellbore 3305 by expanding the casing 3335 in the radial direction into intimate contact with the interior walls of the wellbore 3305. The casing 3335 may be expanded in the radial direction using any number of conventional commercially available methods. In an exemplary embodiment, the casing 3335 is expanded in the radial direction using one or more of the processes and apparatus described within the present disclosure.

The seals 3340 prevent the passage of fluids and other materials within the annular region 3365 between the solid casings 3335 and 3350 and the wellbore 3305. The seals 3340 may comprise any number of conventional commercially available sealing materials suitable for sealing a casing in a wellbore such as, for example, lead, rubber or epoxy. In an exemplary embodiment, the seals 3340 comprise Stratalok epoxy material available from Halliburton Energy Services.

The slotted casing 3345 permits fluids and other materials to pass into and out of the interior of the slotted casing 3345 from and to the annular region 3365. In this manner, oil and gas may be produced from a producing subterranean zone within a subterranean formation. The slotted casing 3345 may comprise any number of conventional commercially available sections of slotted tubular casing. In an exemplary embodiment, the slotted casing 3345 comprises expandable slotted tubular casing available from Petroline in Aberdeen, Scotland. In an exemplary embodiment, the slotted casing

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145 comprises expandable slotted sandscreen tubular casing available from Petroline in Aberdeen, Scotland.

The slotted casing 3345 is preferably coupled to one or more solid casing 3335. The slotted casing 3345 may be coupled to the solid casing 3335 using any number of conventional commercially available processes such as, for example, welding, or slotted or solid expandable connectors. In an exemplary embodiment, the slotted casing 3345 is coupled to the solid casing 3335 by expandable solid connectors.

The slotted casing 3345 is preferably coupled to one or more intermediate solid casings 3350. The slotted casing 3345 may be coupled to the intermediate solid casing 3350 using any number of conventional commercially available processes such as, for example, welding or expandable solid or slotted connectors. In an exemplary embodiment, the slotted casing 3345 is coupled to the intermediate solid casing 3350 by expandable solid connectors.

The last section of slotted casing 3345 is preferably coupled to the shoe 3355. The last slotted casing 3345 may be coupled to the shoe 3355 using any number of conventional commercially available processes such as, for example, welding or expandable solid or slotted connectors. In an exemplary embodiment, the last slotted casing 3345 is coupled to the shoe 3355 by an expandable solid connector.

In an alternative embodiment, the shoe 3355 is coupled directly to the last one of the intermediate solid casings 3350.

In an exemplary embodiment, the slotted casings 3345 are positioned within the wellbore 3305 by expanding the slotted casings 3345 in a radial direction into intimate contact with the interior walls of the wellbore 3305. The slotted casings 3345 may be expanded in a radial direction using any number of conventional commercially available processes. In an exemplary embodiment, the slotted casings 3345 are expanded in the radial direction using one or more of the processes and apparatus disclosed in the present disclosure with reference to FIGS. 14a-20.

The intermediate solid casing 3350 permits fluids and other materials to pass between adjacent slotted casings 3345. The intermediate solid casing 3350 may comprise any number of conventional commercially available sections of solid tubular casing such as, for example, oilfield tubulars fabricated from chromium steel or fiberglass. In an exemplary embodiment, the intermediate solid casing 3350 comprises oilfield tubulars available from foreign and domestic steel mills.

The intermediate solid casing 3350 is preferably coupled to one or more sections of the slotted casing 3345. The intermediate solid casing 3350 may be coupled to the slotted casing 3345 using any number of conventional commercially available processes such as, for example, welding, or solid or slotted expandable connectors. In an exemplary embodiment, the intermediate solid casing 3350 is coupled to the slotted casing 3345 by expandable solid connectors. The intermediate solid casing 3350 may comprise a plurality of such intermediate solid casing 3350.

In an exemplary embodiment, each intermediate solid casing 3350 includes one more valve members 3370 for controlling the flow of fluids and other materials within the interior region of the intermediate casing 3350. In an alternative embodiment, as will be recognized by persons having ordinary skill in the art and the benefit of the present disclosure, during the production mode of operation, an internal tubular string with various arrangements of packers, perforated tubing, sliding sleeves, and valves may be employed within the apparatus to provide various options

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for commingling and isolating subterranean zones from each other while providing a fluid path to the surface.

In an exemplary embodiment, the intermediate casing 3350 is placed into the wellbore 3305 by expanding the intermediate casing 3350 in the radial direction into intimate contact with the interior walls of the wellbore 3305. The intermediate casing 3350 may be expanded in the radial direction using any number of conventional commercially available methods.

In an alternative embodiment, one or more of the intermediate solid casings 3350 may be omitted. In an exemplary embodiment, one or more of the slotted casings 3345 are provided with one or more seals 3340.

The shoe 3355 provides a support member for the apparatus 3330. In this manner, various production and exploration tools may be supported by the shoe 3350. The shoe 3350 may comprise any number of conventional commercially available shoes suitable for use in a wellbore such as, for example, cement filled shoe, or an aluminum or composite shoe. In an exemplary embodiment, the shoe 3350 comprises an aluminum shoe available from Halliburton. In an exemplary embodiment, the shoe 3355 is selected to provide sufficient strength in compression and tension to permit the use of high capacity production and exploration tools.

In an exemplary embodiment, the apparatus 3330 includes a plurality of solid casings 3335, a plurality of seals 3340, a plurality of slotted casings 3345, a plurality of intermediate solid casings 3350, and a shoe 3355. More generally, the apparatus 3330 may comprise one or more solid casings 3335, each with one or more valve members 3360, n slotted casings 3345, n-1 intermediate solid casings 3350, each with one or more valve members 3370, and a shoe 3355.

During operation of the apparatus 3330, oil and gas may be controllably produced from the targeted oil sand zone 3325 using the slotted casings 3345. The oil and gas may then be transported to a surface location using the solid casing 3335. The use of intermediate solid casings 3350 with valve members 3370 permits isolated sections of the zone 3325 to be selectively isolated for production. The seals 3340 permit the zone 3325 to be fluidically isolated from the zone 3320. The seals 3340 further permits isolated sections of the zone 3325 to be fluidically isolated from each other. In this manner, the apparatus 3330 permits unwanted and/or non-productive subterranean zones to be fluidically isolated.

In an alternative embodiment, as will be recognized by persons having ordinary skill in the art and also having the benefit of the present disclosure, during the production mode of operation, an internal tubular string with various arrangements of packers, perforated tubing, sliding sleeves, and valves may be employed within the apparatus to provide various options for commingling and isolating subterranean zones from each other while providing a fluid path to the surface.

A method of creating a casing in a borehole located in a subterranean formation has been described that includes installing a tubular liner and a mandrel in the borehole. A body of fluidic material is then injected into the borehole. The tubular liner is then radially expanded by extruding the liner off of the mandrel. The injecting preferably includes injecting a hardenable fluidic sealing material into an annular region located between the borehole and the exterior of the tubular liner; and a non hardenable fluidic material into an interior region of the tubular liner below the mandrel. The method preferably includes fluidically isolating the annular region from the interior region before injecting the second

quantity of the non hardenable sealing material into the interior region. The injecting the hardenable fluidic sealing material is preferably provided at operating pressures and flow rates ranging from about 0 to 5000 psi and 0 to 1,500 gallons/min. The injecting of the non hardenable fluidic material is preferably provided at operating pressures and flow rates ranging from about 500 to 9000 psi and 40 to 3,000 gallons/min. The injecting of the non hardenable fluidic material is preferably provided at reduced operating pressures and flow rates during an end portion of the extruding. The non hardenable fluidic material is preferably injected below the mandrel. The method preferably includes pressurizing a region of the tubular liner below the mandrel. The region of the tubular liner below the mandrel is preferably pressurized to pressures ranging from about 500 to 9,000 psi. The method preferably includes fluidically isolating an interior region of the tubular liner from an exterior region of the tubular liner. The method further preferably includes curing the hardenable sealing material, and removing at least a portion of the cured sealing material located within the tubular liner. The method further preferably includes overlapping the tubular liner with an existing wellbore casing. The method further preferably includes sealing the overlap between the tubular liner and the existing wellbore casing. The method further preferably includes supporting the extruded tubular liner using the overlap with the existing wellbore casing. The method further preferably includes testing the integrity of the seal in the overlap between the tubular liner and the existing wellbore casing. The method further preferably includes removing at least a portion of the hardenable fluidic sealing material within the tubular liner before curing. The method further preferably includes lubricating the surface of the mandrel. The method further preferably includes absorbing shock. The method further preferably includes catching the mandrel upon the completion of the extruding.

An apparatus for creating a casing in a borehole located in a subterranean formation has been described that includes a support member, a mandrel, a tubular member, and a shoe. The support member includes a first fluid passage. The mandrel is coupled to the support member and includes a second fluid passage. The tubular member is coupled to the mandrel. The shoe is coupled to the tubular liner and includes a third fluid passage. The first, second and third fluid passages are operably coupled. The support member preferably further includes a pressure relief passage, and a flow control valve coupled to the first fluid passage and the pressure relief passage. The support member further preferably includes a shock absorber. The support member preferably includes one or more sealing members adapted to prevent foreign material from entering an interior region of the tubular member. The mandrel is preferably expandable. The tubular member is preferably fabricated from materials selected from the group consisting of Oilfield Country Tubular Goods, 13 chromium steel tubing/casing, and plastic casing. The tubular member preferably has inner and outer diameters ranging from about 3 to 15.5 inches and 3.5 to 16 inches, respectively. The tubular member preferably has a plastic yield point ranging from about 40,000 to 135,000 psi. The tubular member preferably includes one or more sealing members at an end portion. The tubular member preferably includes one or more pressure relief holes at an end portion. The tubular member preferably includes a catching member at an end portion for slowing down the mandrel. The shoe preferably includes an inlet port coupled

to the third fluid passage, the inlet port adapted to receive a plug for blocking the inlet port. The shoe preferably is drillable.

A method of joining a second tubular member to a first tubular member, the first tubular member having an inner diameter greater than an outer diameter of the second tubular member, has been described that includes positioning a mandrel within an interior region of the second tubular member, positioning the first and second tubular members in an overlapping relationship, pressurizing a portion of the interior region of the second tubular member; and extruding the second tubular member off of the mandrel into engagement with the first tubular member. The pressurizing of the portion of the interior region of the second tubular member is preferably provided at operating pressures ranging from about 500 to 9,000 psi. The pressurizing of the portion of the interior region of the second tubular member is preferably provided at reduced operating pressures during a latter portion of the extruding. The method further preferably includes sealing the overlap between the first and second tubular members. The method further preferably includes supporting the extruded first tubular member using the overlap with the second tubular member. The method further preferably includes lubricating the surface of the mandrel. The method further preferably includes absorbing shock.

A liner for use in creating a new section of wellbore casing in a subterranean formation adjacent to an already existing section of wellbore casing has been described that includes an annular member. The annular member includes one or more sealing members at an end portion of the annular member, and one or more pressure relief passages at an end portion of the annular member.

A wellbore casing has been described that includes a tubular liner and an annular body of a cured fluidic sealing material. The tubular liner is formed by the process of extruding the tubular liner off of a mandrel. The tubular liner is preferably formed by the process of placing the tubular liner and mandrel within the wellbore, and pressurizing an interior portion of the tubular liner. The annular body of the cured fluidic sealing material is preferably formed by the process of injecting a body of hardenable fluidic sealing material into an annular region external of the tubular liner. During the pressurizing, the interior portion of the tubular liner is preferably fluidically isolated from an exterior portion of the tubular liner. The interior portion of the tubular liner is preferably pressurized to pressures ranging from about 500 to 9,000 psi. The tubular liner preferably overlaps with an existing wellbore casing. The wellbore casing preferably further includes a seal positioned in the overlap between the tubular liner and the existing wellbore casing. Tubular liner is preferably supported the overlap with the existing wellbore casing.

A method of repairing an existing section of a wellbore casing within a borehole has been described that includes installing a tubular liner and a mandrel within the wellbore casing, injecting a body of a fluidic material into the borehole, pressurizing a portion of an interior region of the tubular liner, and radially expanding the liner in the borehole by extruding the liner off of the mandrel. In an exemplary embodiment, the fluidic material is selected from the group consisting of slag mix, cement, drilling mud, and epoxy. In an exemplary embodiment, the method further includes fluidically isolating an interior region of the tubular liner from an exterior region of the tubular liner. In an exemplary embodiment, the injecting of the body of fluidic material is provided at operating pressures and flow rates ranging from about 500 to 9,000 psi and 40 to 3,000 gallons/min. In an

exemplary embodiment, the injecting of the body of fluidic material is provided at reduced operating pressures and flow rates during an end portion of the extruding. In an exemplary embodiment, the fluidic material is injected below the mandrel. In an exemplary embodiment, a region of the tubular liner below the mandrel is pressurized. In an exemplary embodiment, the region of the tubular liner below the mandrel is pressurized to pressures ranging from about 500 to 9,000 psi. In an exemplary embodiment, the method further includes overlapping the tubular liner with the existing wellbore casing. In an exemplary embodiment, the method further includes sealing the interface between the tubular liner and the existing wellbore casing. In an exemplary embodiment, the method further includes supporting the extruded tubular liner using the existing wellbore casing. In an exemplary embodiment, the method further includes testing the integrity of the seal in the interface between the tubular liner and the existing wellbore casing. In an exemplary embodiment, method further includes lubricating the surface of the mandrel. In an exemplary embodiment, the method further includes absorbing shock. In an exemplary embodiment, the method further includes catching the mandrel upon the completion of the extruding. In an exemplary embodiment, the method further includes expanding the mandrel in a radial direction.

A tie-back liner for lining an existing wellbore casing has been described that includes a tubular liner and an annular body of a cured fluidic sealing material. The tubular liner is formed by the process of extruding the tubular liner off of a mandrel. The annular body of a cured fluidic sealing material is coupled to the tubular liner. In an exemplary embodiment, the tubular liner is formed by the process of placing the tubular liner and mandrel within the wellbore, and pressurizing an interior portion of the tubular liner. In an exemplary embodiment, during the pressurizing, the interior portion of the tubular liner is fluidically isolated from an exterior portion of the tubular liner. In an exemplary embodiment, the interior portion of the tubular liner is pressurized at pressures ranging from about 500 to 9,000 psi. In an exemplary embodiment, the annular body of a cured fluidic sealing material is formed by the process of injecting a body of hardenable fluidic sealing material into an annular region between the existing wellbore casing and the tubular liner. In an exemplary embodiment, the tubular liner overlaps with another existing wellbore casing. In an exemplary embodiment, the tie-back liner further includes a seal positioned in the overlap between the tubular liner and the other existing wellbore casing. In an exemplary embodiment, tubular liner is supported by the overlap with the other existing wellbore casing.

An apparatus for expanding a tubular member has been described that includes a support member, a mandrel, a tubular member, and a shoe. The support member includes a first fluid passage. The mandrel is coupled to the support member. The mandrel includes a second fluid passage operably coupled to the first fluid passage, an interior portion, and an exterior portion. The interior portion of the mandrel is drillable. The tubular member is coupled to the mandrel. The shoe is coupled to the tubular member. The shoe includes a third fluid passage operably coupled to the second fluid passage, an interior portion, and an exterior portion. The interior portion of the shoe is drillable. Preferably, the interior portion of the mandrel includes a tubular member and a load bearing member. Preferably, the load bearing member comprises a drillable body. Preferably, the interior portion of the shoe includes a tubular member, and a load bearing member. Preferably, the load bearing member com-

prises a drillable body. Preferably, the exterior portion of the mandrel comprises an expansion cone. Preferably, the expansion cone is fabricated from materials selected from the group consisting of tool steel, titanium, and ceramic. Preferably, the expansion cone has a surface hardness ranging from about 58 to 62 Rockwell C. Preferably at least a portion of the apparatus is drillable.

A wellhead has also been described that includes an outer casing and a plurality of substantially concentric and overlapping inner casings coupled to the outer casing. Each inner casing is supported by contact pressure between an outer surface of the inner casing and an inner surface of the outer casing. In an exemplary embodiment, the outer casing has a yield strength ranging from about 40,000 to 135,000 psi. In an exemplary embodiment, the outer casing has a burst strength ranging from about 5,000 to 20,000 psi. In an exemplary embodiment, the contact pressure between the inner casings and the outer casing ranges from about 500 to 10,000 psi. In an exemplary embodiment, one or more of the inner casings include one or more sealing members that contact with an inner surface of the outer casing. In an exemplary embodiment, the sealing members are selected from the group consisting of lead, rubber, Teflon, epoxy, and plastic. In an exemplary embodiment, a Christmas tree is coupled to the outer casing. In an exemplary embodiment, a drilling spool is coupled to the outer casing. In an exemplary embodiment, at least one of the inner casings is a production casing.

A wellhead has also been described that includes an outer casing at least partially positioned within a wellbore and a plurality of substantially concentric inner casings coupled to the interior surface of the outer casing by the process of expanding one or more of the inner casings into contact with at least a portion of the interior surface of the outer casing. In an exemplary embodiment, the inner casings are expanded by extruding the inner casings off of a mandrel. In an exemplary embodiment, the inner casings are expanded by the process of placing the inner casing and a mandrel within the wellbore; and pressurizing an interior portion of the inner casing. In an exemplary embodiment, during the pressurizing, the interior portion of the inner casing is fluidically isolated from an exterior portion of the inner casing. In an exemplary embodiment, the interior portion of the inner casing is pressurized at pressures ranging from about 500 to 9,000 psi. In an exemplary embodiment, one or more seals are positioned in the interface between the inner casings and the outer casing. In an exemplary embodiment, the inner casings are supported by their contact with the outer casing.

A method of forming a wellhead has also been described that includes drilling a wellbore. An outer casing is positioned at least partially within an upper portion of the wellbore. A first tubular member is positioned within the outer casing. At least a portion of the first tubular member is expanded into contact with an interior surface of the outer casing. A second tubular member is positioned within the outer casing and the first tubular member. At least a portion of the second tubular member is expanded into contact with an interior portion of the outer casing. In an exemplary embodiment, at least a portion of the interior of the first tubular member is pressurized. In an exemplary embodiment, at least a portion of the interior of the second tubular member is pressurized. In an exemplary embodiment, at least a portion of the interiors of the first and second tubular members are pressurized. In an exemplary embodiment, the pressurizing of the portion of the interior region of the first tubular member is provided at operating pressures ranging

from about 500 to 9,000 psi. In an exemplary embodiment, the pressurizing of the portion of the interior region of the second tubular member is provided at operating pressures ranging from about 500 to 9,000 psi. In an exemplary embodiment, the pressurizing of the portion of the interior region of the first and second tubular members is provided at operating pressures ranging from about 500 to 9,000 psi. In an exemplary embodiment, the pressurizing of the portion of the interior region of the first tubular member is provided at reduced operating pressures during a latter portion of the expansion. In an exemplary embodiment, the pressurizing of the portion of the interior region of the second tubular member is provided at reduced operating pressures during a latter portion of the expansion. In an exemplary embodiment, the pressurizing of the portion of the interior region of the first and second tubular members is provided at reduced operating pressures during a latter portion of the expansions. In an exemplary embodiment, the contact between the first tubular member and the outer casing is sealed. In an exemplary embodiment, the contact between the second tubular member and the outer casing is sealed. In an exemplary embodiment, the contact between the first and second tubular members and the outer casing is sealed. In an exemplary embodiment, the expanded first tubular member is supported using the contact with the outer casing. In an exemplary embodiment, the expanded second tubular member is supported using the contact with the outer casing. In an exemplary embodiment, the expanded first and second tubular members are supported using their contacts with the outer casing. In an exemplary embodiment, the first and second tubular members are extruded off of a mandrel. In an exemplary embodiment, the surface of the mandrel is lubricated. In an exemplary embodiment, shock is absorbed. In an exemplary embodiment, the mandrel is expanded in a radial direction. In an exemplary embodiment, the first and second tubular members are positioned in an overlapping relationship. In an exemplary embodiment, an interior region of the first tubular member is fluidically isolated from an exterior region of the first tubular member. In an exemplary embodiment, an interior region of the second tubular member is fluidically isolated from an exterior region of the second tubular member. In an exemplary embodiment, the interior region of the first tubular member is fluidically isolated from the region exterior to the first tubular member by injecting one or more plugs into the interior of the first tubular member. In an exemplary embodiment, the interior region of the second tubular member is fluidically isolated from the region exterior to the second tubular member by injecting one or more plugs into the interior of the second tubular member. In an exemplary embodiment, the pressurizing of the portion of the interior region of the first tubular member is provided by injecting a fluidic material at operating pressures and flow rates ranging from about 500 to 9,000 psi and 40 to 3,000 gallons/minute. In an exemplary embodiment, the pressurizing of the portion of the interior region of the second tubular member is provided by injecting a fluidic material at operating pressures and flow rates ranging from about 500 to 9,000 psi and 40 to 3,000 gallons/minute. In an exemplary embodiment, fluidic material is injected beyond the mandrel. In an exemplary embodiment, a region of the tubular members beyond the mandrel is pressurized. In an exemplary embodiment, the region of the tubular members beyond the mandrel is pressurized to pressures ranging from about 500 to 9,000 psi. In an exemplary embodiment, the first tubular member comprises a production casing. In an exemplary embodiment, the contact between the first tubular member and the outer

casing is sealed. In an exemplary embodiment, the contact between the second tubular member and the outer casing is sealed. In an exemplary embodiment, the expanded first tubular member is supported using the outer casing. In an exemplary embodiment, the expanded second tubular member is supported using the outer casing. In an exemplary embodiment, the integrity of the seal in the contact between the first tubular member and the outer casing is tested. In an exemplary embodiment, the integrity of the seal in the contact between the second tubular member and the outer casing is tested. In an exemplary embodiment, the mandrel is caught upon the completion of the extruding. In an exemplary embodiment, the mandrel is drilled out. In an exemplary embodiment, the mandrel is supported with coiled tubing. In an exemplary embodiment, the mandrel is coupled to a drillable shoe.

An apparatus has also been described that includes an outer tubular member, and a plurality of substantially concentric and overlapping inner tubular members coupled to the outer tubular member. Each inner tubular member is supported by contact pressure between an outer surface of the inner casing and an inner surface of the outer inner tubular member. In an exemplary embodiment, the outer tubular member has a yield strength ranging from about 40,000 to 135,000 psi. In an exemplary embodiment, the outer tubular member has a burst strength ranging from about 5,000 to 20,000 psi. In an exemplary embodiment, the contact pressure between the inner tubular members and the outer tubular member ranges from about 500 to 10,000 psi. In an exemplary embodiment, one or more of the inner tubular members include one or more sealing members that contact with an inner surface of the outer tubular member. In an exemplary embodiment, the sealing members are selected from the group consisting of rubber, lead, plastic, and epoxy.

An apparatus has also been described that includes an outer tubular member, and a plurality of substantially concentric inner tubular members coupled to the interior surface of the outer tubular member by the process of expanding one or more of the inner tubular members into contact with at least a portion of the interior surface of the outer tubular member. In an exemplary embodiment, the inner tubular members are expanded by extruding the inner tubular members off of a mandrel. In an exemplary embodiment, the inner tubular members are expanded by the process of: placing the inner tubular members and a mandrel within the outer tubular member; and pressurizing an interior portion of the inner casing. In an exemplary embodiment, during the pressurizing, the interior portion of the inner tubular member is fluidically isolated from an exterior portion of the inner tubular member. In an exemplary embodiment, the interior portion of the inner tubular member is pressurized at pressures ranging from about 500 to 9,000 psi. In an exemplary embodiment, the apparatus further includes one or more seals positioned in the interface between the inner tubular members and the outer tubular member. In an exemplary embodiment, the inner tubular members are supported by their contact with the outer tubular member.

A wellbore casing has also been described that includes a first tubular member, and a second tubular member coupled to the first tubular member in an overlapping relationship. The inner diameter of the first tubular member is substantially equal to the inner diameter of the second tubular member. In an exemplary embodiment, the first tubular member includes a first thin wall section, wherein the second tubular member includes a second thin wall section, and wherein the first thin wall section is coupled to the second thin wall section. In an exemplary embodiment, first and

second thin wall sections are deformed. In an exemplary embodiment, the first tubular member includes a first compressible member coupled to the first thin wall section, and wherein the second tubular member includes a second compressible member coupled to the second thin wall section. In an exemplary embodiment, the first thin wall section and the first compressible member are coupled to the second thin wall section and the second compressible member. In an exemplary embodiment, the first and second thin wall sections and the first and second compressible members are deformed.

A wellbore casing has also been described that includes a tubular member including at least one thin wall section and a thick wall section, and

a compressible annular member coupled to each thin wall section. In an exemplary embodiment, the compressible annular member is fabricated from materials selected from the group consisting of rubber, plastic, metal and epoxy. In an exemplary embodiment, the wall thickness of the thin wall section ranges from about 50 to 100% of the wall thickness of the thick wall section. In an exemplary embodiment, the length of the thin wall section ranges from about 120 to 2400 inches. In an exemplary embodiment, the compressible annular member is positioned along the thin wall section. In an exemplary embodiment, the compressible annular member is positioned along the thin and thick wall sections. In an exemplary embodiment, the tubular member is fabricated from materials selected from the group consisting of oilfield country tubular goods, stainless steel, low alloy steel, carbon steel, automotive grade steel, plastics, fiberglass, high strength and/or deformable materials. In an exemplary embodiment, the wellbore casing includes a first thin wall at a first end of the casing, and a second thin wall at a second end of the casing.

A method of creating a casing in a borehole located in a subterranean formation has also been described that includes supporting a tubular liner and a mandrel in the borehole using a support member, injecting fluidic material into the borehole, pressurizing an interior region of the mandrel, displacing a portion of the mandrel relative to the support member, and radially expanding the tubular liner. In an exemplary embodiment, the injecting includes injecting hardenable fluidic sealing material into an annular region located between the borehole and the exterior of the tubular liner, and injecting non hardenable fluidic material into an interior region of the mandrel. In an exemplary embodiment, the method further includes fluidically isolating the annular region from the interior region before injecting the non hardenable fluidic material into the interior region of the mandrel. In an exemplary embodiment, the injecting of the hardenable fluidic sealing material is provided at operating pressures and flow rates ranging from about 0 to 5,000 psi and 0 to 1,500 gallons/min. In an exemplary embodiment, the injecting of the non hardenable fluidic material is provided at operating pressures and flow rates ranging from about 500 to 9,000 psi and 40 to 3,000 gallons/min. In an exemplary embodiment, the injecting of the non hardenable fluidic material is provided at reduced operating pressures and flow rates during an end portion of the radial expansion. In an exemplary embodiment, the fluidic material is injected into one or more pressure chambers. In an exemplary embodiment, the one or more pressure chambers are pressurized. In an exemplary embodiment, the pressure chambers are pressurized to pressures ranging from about 500 to 9,000 psi. In an exemplary embodiment, the method further includes fluidically isolating an interior region of the mandrel from an exterior region of the mandrel. In an exemplary

embodiment, the interior region of the mandrel is isolated from the region exterior to the mandrel by inserting one or more plugs into the injected fluidic material. In an exemplary embodiment, the method further includes curing at least a portion of the fluidic material, and removing at least a portion of the cured fluidic material located within the tubular liner. In an exemplary embodiment, the method further includes overlapping the tubular liner with an existing wellbore casing. In an exemplary embodiment, the method further includes sealing the overlap between the tubular liner and the existing wellbore casing. In an exemplary embodiment, the method further includes supporting the extruded tubular liner using the overlap with the existing wellbore casing. In an exemplary embodiment, the method further includes testing the integrity of the seal in the overlap between the tubular liner and the existing wellbore casing. In an exemplary embodiment, the method further includes removing at least a portion of the hardenable fluidic sealing material within the tubular liner before curing. In an exemplary embodiment, the method further includes lubricating the surface of the mandrel. In an exemplary embodiment, the method further includes absorbing shock. In an exemplary embodiment, the method further includes catching the mandrel upon the completion of the extruding. In an exemplary embodiment, the method further includes drilling out the mandrel. In an exemplary embodiment, the method further includes supporting the mandrel with coiled tubing. In an exemplary embodiment, the mandrel reciprocates. In an exemplary embodiment, the mandrel is displaced in a first direction during the pressurization of the interior region of the mandrel, and the mandrel is displaced in a second direction during a de-pressurization of the interior region of the mandrel. In an exemplary embodiment, the tubular liner is maintained in a substantially stationary position during the pressurization of the interior region of the mandrel. In an exemplary embodiment, the tubular liner is supported by the mandrel during a de-pressurization of the interior region of the mandrel.

A wellbore casing has also been described that includes a first tubular member having a first inside diameter, and a second tubular member having a second inside diameter substantially equal to the first inside diameter coupled to the first tubular member in an overlapping relationship. The first and second tubular members are coupled by the process of deforming a portion of the second tubular member into contact with a portion of the first tubular member. In an exemplary embodiment, the second tubular member is deformed by the process of placing the first and second tubular members in an overlapping relationship, radially expanding at least a portion of the first tubular member, and radially expanding the second tubular member. In an exemplary embodiment, the second tubular member is radially expanded by the process of supporting the second tubular member and a mandrel within the wellbore using a support member, injecting a fluidic material into the wellbore, pressurizing an interior region of the mandrel, and displacing a portion of the mandrel relative to the support member. In an exemplary embodiment, the injecting includes injecting hardenable fluidic sealing material into an annular region located between the borehole and the exterior of the second liner, and injecting non hardenable fluidic material into an interior region of the mandrel. In an exemplary embodiment, the wellbore casing further includes fluidically isolating the annular region from the interior region of the mandrel before injecting the non hardenable fluidic material into the interior region of the mandrel. In an exemplary embodiment, the injecting of the hardenable fluidic sealing material is pro-

vided at operating pressures and flow rates ranging from about 0 to 5,000 psi and 0 to 1,500 gallons/min. In an exemplary embodiment, the injecting of the non hardenable fluidic material is provided at operating pressures and flow rates ranging from about 500 to 9,000 psi and 40 to 3,000 gallons/min. In an exemplary embodiment, the injecting of the non hardenable fluidic material is provided at reduced operating pressures and flow rates during an end portion of the radial expansion. In an exemplary embodiment, the fluidic material is injected into one or more pressure chambers. In an exemplary embodiment, one or more pressure chambers are pressurized. In an exemplary embodiment, the pressure chambers are pressurized to pressures ranging from about 500 to 9,000 psi. In an exemplary embodiment, the wellbore casing further includes fluidically isolating an interior region of the mandrel from an exterior region of the mandrel. In an exemplary embodiment, the interior region of the mandrel is isolated from the region exterior to the mandrel by inserting one or more plugs into the injected fluidic material. In an exemplary embodiment, the wellbore casing further includes curing at least a portion of the fluidic material, and removing at least a portion of the cured fluidic material located within the second tubular liner. In an exemplary embodiment, the wellbore casing further includes sealing the overlap between the first and second tubular liners. In an exemplary embodiment, the wellbore casing further includes supporting the second tubular liner using the overlap with the first tubular liner. In an exemplary embodiment, the wellbore casing further includes testing the integrity of the seal in the overlap between the first and second tubular liners. In an exemplary embodiment, the wellbore casing further includes removing at least a portion of the hardenable fluidic sealing material within the second tubular liner before curing. In an exemplary embodiment, the wellbore casing further includes lubricating the surface of the mandrel. In an exemplary embodiment, the wellbore casing further includes absorbing shock. In an exemplary embodiment, the wellbore casing further includes catching the mandrel upon the completion of the radial expansion. In an exemplary embodiment, the wellbore casing further includes drilling out the mandrel. In an exemplary embodiment, the wellbore casing further include supporting the mandrel with coiled tubing. In an exemplary embodiment, the mandrel reciprocates. In an exemplary embodiment, the mandrel is displaced in a first direction during the pressurization of the interior region of the mandrel; and wherein the mandrel is displaced in a second direction during a de-pressurization of the interior region of the mandrel. In an exemplary embodiment, the second tubular liner is maintained in a substantially stationary position during the pressurization of the interior region of the mandrel. In an exemplary embodiment, the second tubular liner is supported by the mandrel during a de-pressurization of the interior region of the mandrel.

An apparatus for expanding a tubular member has also been described that includes a support member including a fluid passage, a mandrel movably coupled to the support member including an expansion cone, at least one pressure chamber defined by and positioned between the support member and mandrel fluidically coupled to the first fluid passage, and one or more releasable supports coupled to the support member adapted to support the tubular member. In an exemplary embodiment, the fluid passage includes a throat passage having a reduced inner diameter. In an exemplary embodiment, the mandrel includes one or more annular pistons. In an exemplary embodiment, the apparatus includes a plurality of pressure chambers. In an exemplary embodiment, the pressure chambers are at least partially

defined by annular pistons. In an exemplary embodiment, the releasable supports are positioned below the mandrel. In an exemplary embodiment, the releasable supports are positioned above the mandrel. In an exemplary embodiment, the releasable supports comprise hydraulic slips. In an exemplary embodiment, the releasable supports comprise mechanical slips. In an exemplary embodiment, the releasable supports comprise drag blocks. In an exemplary embodiment, the mandrel includes one or more annular pistons, and an expansion cone coupled to the annular pistons. In an exemplary embodiment, one or more of the annular pistons include an expansion cone. In an exemplary embodiment, the pressure chambers comprise annular pressure chambers.

An apparatus has also been described that includes one or more solid tubular members, each solid tubular member including one or more external seals, one or more slotted tubular members coupled to the solid tubular members, and a shoe coupled to one of the slotted tubular members. In an exemplary embodiment, the apparatus further includes one or more intermediate solid tubular members coupled to and interleaved among the slotted tubular members, each intermediate solid tubular member including one or more external seals. In an exemplary embodiment, the apparatus further includes one or more valve members. In an exemplary embodiment, one or more of the intermediate solid tubular members include one or more valve members.

A method of joining a second tubular member to a first tubular member, the first tubular member having an inner diameter greater than an outer diameter of the second tubular member, has also been described that includes positioning a mandrel within an interior region of the second tubular member, pressurizing a portion of the interior region of the mandrel, displacing the mandrel relative to the second tubular member, and extruding at least a portion of the second tubular member off of the mandrel into engagement with the first tubular member. In an exemplary embodiment, the pressurizing of the portion of the interior region of the mandrel is provided at operating pressures ranging from about 500 to 9,000 psi. In an exemplary embodiment, the pressurizing of the portion of the interior region of the mandrel is provided at reduced operating pressures during a latter portion of the extruding. In an exemplary embodiment, the method further includes sealing the interface between the first and second tubular members. In an exemplary embodiment, the method further includes supporting the extruded second tubular member using the interface with the first tubular member. In an exemplary embodiment, the method further includes lubricating the surface of the mandrel. In an exemplary embodiment, the method further includes absorbing shock. In an exemplary embodiment, the method further includes positioning the first and second tubular members in an overlapping relationship. In an exemplary embodiment, the method further includes fluidically isolating an interior region of the mandrel an exterior region of the mandrel. In an exemplary embodiment, the interior region of the mandrel is fluidically isolated from the region exterior to the mandrel by injecting one or more plugs into the interior of the mandrel. In an exemplary embodiment, the pressurizing of the portion of the interior region of the mandrel is provided by injecting a fluidic material at operating pressures and flow rates ranging from about 500 to 9,000 psi and 40 to 3,000 gallons/minute. In an exemplary embodiment, the method further includes injecting fluidic material beyond the mandrel. In an exemplary embodiment, one or more pressure chambers defined by the mandrel are pressurized. In an exemplary embodiment, the pressure chambers are

pressurized to pressures ranging from about 500 to 9,000 psi. In an exemplary embodiment, the first tubular member comprises an existing section of a wellbore. In an exemplary embodiment, the method further includes sealing the interface between the first and second tubular members. In an exemplary embodiment, the method further includes supporting the extruded second tubular member using the first tubular member. In an exemplary embodiment, the method further includes testing the integrity of the seal in the interface between the first tubular member and the second tubular member. In an exemplary embodiment, the method further includes catching the mandrel upon the completion of the extruding. In an exemplary embodiment, the method further includes drilling out the mandrel. In an exemplary embodiment, the method further include supporting the mandrel with coiled tubing. In an exemplary embodiment, the method further includes coupling the mandrel to a drillable shoe. In an exemplary embodiment, the mandrel is displaced in the longitudinal direction. In an exemplary embodiment, the mandrel is displaced in a first direction during the pressurization and in a second direction during a de-pressurization.

An apparatus has also been described that includes one or more primary solid tubulars, each primary solid tubular including one or more external annular seals, n slotted tubulars coupled to the primary solid tubulars, n-1 intermediate solid tubulars coupled to and interleaved among the slotted tubulars, each intermediate solid tubular including one or more external annular seals, and a shoe coupled to one of the slotted tubulars.

A method of isolating a first subterranean zone from a second subterranean zone in a wellbore has also been described that includes positioning one or more primary solid tubulars within the wellbore, the primary solid tubulars traversing the first subterranean zone, positioning one or more slotted tubulars within the wellbore, the slotted tubulars traversing the second subterranean zone, fluidically coupling the slotted tubulars and the solid tubulars, and preventing the passage of fluids from the first subterranean zone to the second subterranean zone within the wellbore external to the solid and slotted tubulars.

A method of extracting materials from a producing subterranean zone in a wellbore, at least a portion of the wellbore including a casing, has also been described that includes positioning one or more primary solid tubulars within the wellbore, fluidically coupling the primary solid tubulars with the casing, positioning one or more slotted tubulars within the wellbore, the slotted tubulars traversing the producing subterranean zone, fluidically coupling the slotted tubulars with the solid tubulars, fluidically isolating the producing subterranean zone from at least one other subterranean zone within the wellbore, and fluidically coupling at least one of the slotted tubulars from the producing subterranean zone. In an exemplary embodiment, the method further includes controllably fluidically decoupling at least one of the slotted tubulars from at least one other of the slotted tubulars.

Although illustrative embodiments of the invention have been shown and described, a wide range of modification, changes and substitution is contemplated in the foregoing disclosure. In some instances, some features of the present invention may be employed without a corresponding use of the other features. Accordingly, it is appropriate that the appended claims be construed broadly and in a manner consistent with the scope of the invention.

What is claimed is:

1. A method of creating a casing in a borehole located in a subterranean formation, comprising:
 - supporting a tubular liner and an expansion device in the borehole using a support member;
 - injecting fluidic material into the borehole;
 - pressurizing an interior region of the expansion device;
 - displacing a portion of the expansion device relative to the support member and the tubular liner in the longitudinal direction; and
 - radially expanding the tubular liner.
2. The method of claim 1, wherein the injecting includes:
 - injecting hardenable fluidic sealing material into an annular region located between the borehole and the exterior of the tubular liner; and
 - injecting non hardenable fluidic material into an interior region of the expansion device.
3. The method of claim 2, further comprising:
 - fluidically isolating the annular region from the interior region before injecting the non hardenable fluidic material into the interior region of the expansion device.
4. The method of claim 2, wherein the injecting of the non hardenable fluidic material is provided at reduced operating pressures and flow rates during an end portion of the radial expansion.
5. The method of claim 1, wherein the fluidic material is injected into one or more annular pressure chambers defined within the expansion device.
6. The method of claim 5, further comprising:
 - fluidically isolating the annular pressure chambers defined within the expansion device from an exterior region of the expansion device.
7. The method of claim 1, further comprising:
 - overlapping the tubular liner with an existing wellbore casing.
8. The method of claim 7, further comprising:
 - sealing the overlap between the tubular liner and the existing wellbore casing.
9. The method of claim 7, further comprising:
 - supporting the extruded tubular liner using the overlap with the existing wellbore casing.
10. The method of claim 1, wherein the expansion device reciprocates relative to the support member in the longitudinal direction.
11. The method of claim 1, wherein the expansion device is displaced in a first direction during the pressurization of the interior region of the expansion device; and wherein the expansion device is displaced in a second direction during a de-pressurization of the interior region of the expansion device.
12. The method of claim 1, wherein the tubular liner is maintained in a substantially stationary position by the support member during the pressurization of the interior region of the expansion device.
13. The method of claim 12, wherein the tubular liner is supported by the expansion device during a de-pressurization of the interior region of the expansion device.
14. A method of joining a second tubular member to a first tubular member, the first tubular member having an inner diameter greater than an outer diameter of the second tubular member, comprising:
 - positioning an expansion device within an interior region of the second tubular member;
 - pressurizing a portion of an interior region of the expansion device;
 - displacing the expansion device relative to the second tubular member in the longitudinal direction; and

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extruding at least a portion of the second tubular member off of the expansion device into engagement with a portion of the first tubular member;

wherein the inside diameter of the extruded portion of the second tubular member is substantially equal to the inside diameter of the remaining portion of the first tubular member. 5

15. The method of claim 14, wherein the pressurizing of the portion of the interior region of the expansion device is provided at reduced operating pressures during a latter portion of the extruding. 10

16. The method of claim 14, further comprising: sealing the interface between the first and second tubular members.

17. The method of claim 14, further comprising: supporting the extruded second tubular member using the interface with the portion of the first tubular member. 15

18. The method of claim 14, further comprising: positioning the first and second tubular members in an overlapping relationship. 20

19. The method of claim 14, further comprising: injecting fluidic material beyond the expansion device.

20. The method of claim 14, wherein one or more annular pressure chambers defined by the expansion device are pressurized. 25

21. The method of claim 14, wherein the first tubular member comprises an existing section of a wellbore.

22. The method of claim 14, further comprising: supporting the extruded second tubular member using the portion of the first tubular member. 30

23. The method of claim 14, wherein the expansion device is displaced in the longitudinal direction.

24. The method of claim 14, wherein the expansion device is displaced in a first direction relative to the second tubular member during the pressurization and in a second direction relative to the second tubular member during a de-pressurization. 35

25. A method of isolating a first subterranean zone from a second subterranean zone in a wellbore, comprising: positioning one or more primary solid tubulars within the wellbore, the primary solid tubulars traversing the first subterranean zone; 40

positioning one or more perforated tubulars within the wellbore, the perforated tubulars traversing the second subterranean zone; 45

fluidicly coupling the perforated tubulars and the solid tubulars; and

preventing the passage of fluids from the first subterranean zone to the second subterranean zone within the wellbore external to the solid and perforated tubulars;

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wherein at least one of the solid primary tubulars or the perforated tubulars are radially expanded and plastically deformed within the wellbore by a process comprising:

supporting the solid primary tubular or perforated tubular and an expansion device in the borehole using a support member;

injecting fluidic material into the borehole;

pressurizing an interior region of the expansion device;

displacing a portion of the expansion device relative to the support member and the tubular liner in the longitudinal direction; and

radially expanding and plastically deforming the solid primary tubular or the perforated tubular.

26. A method of extracting materials from a producing subterranean zone in a wellbore, at least a portion of the wellbore including a casing, comprising:

positioning one or more primary solid tubulars within the wellbore;

fluidicly coupling the primary solid tubulars with the casing;

positioning one or more perforated tubulars within the wellbore, the perforated tubulars traversing the producing subterranean zone;

fluidicly coupling the perforated tubulars with the solid tubulars;

fluidicly isolating the producing subterranean zone from at least one other subterranean zone within the wellbore; and

fluidicly coupling at least one of the perforated tubulars to the producing subterranean zone;

wherein at least one of the solid primary tubulars or the perforated tubulars are radially expanded and plastically deformed within the wellbore by a process comprising:

supporting the solid primary tubular or perforated tubular and an expansion device in the borehole using a support member;

injecting fluidic material into the borehole;

pressurizing an interior region of the expansion device;

displacing a portion of the expansion device relative to the support member and the tubular liner in the longitudinal direction; and

radially expanding and plastically deforming the solid primary tubular or the perforated tubular.

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